PB-240 558

PRODUCTION OF LOW-SULFUR GASOLINE

M. W. KELLOGG COMPANY

PREPARED FOR
NATIONAL ENVIRONMENTAL RESEARCH CENTER

JULY 1974

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Catalytic converters are to be installed in the exhaust systems of new cars starting with the 1975 model year. The use of catalytic converters is intended to control carbon monoxide and hydrocarbon emissions. However, the catalysts convert some of the sulfur in gasoline into sulfuric acid mist in the exhaust. The purpose of this study was to determine the impact on oil refineries to produce unleaded, low-sulfur gasolines and also to desulfurize all gasolines produced for United States sales.

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PRODUCTION OF LOW-SULFUR GASOLINE

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PART 1
PRODUCTION OF LOW-SULFUR GASOLINES
(PHASE 1)

CHAPTER 1

INTRODUCTION

This part of the report covers work which was performed under Contract No. 68-02-1308, Environmental Protection Agency, Office of Research and Monitoring, Task No. 10, Phase 1.

The crude mix used in Phase I resulted in capacities of the reformer, catalytic cracker and alkylation units which do not match the average U.S. refinery capacities. Future work planned for Phase II will modify the Phase I study in order to match the average U.S. production capacities of these units.

Future work planned for Phase III will be based on crudes and refinery capacities typical of the Los Angeles area.

Catalytic converters are to be installed in the exhaust systems of new cars starting with the 1975 model year. The use of catalytic converters is intended to control carbon monoxide and hydrocarbon emissions. However, the catalysts convert sulfur in the gasoline into sulfuric acid mists in the exhaust.

The purpose of this study is to determine the impact on oil refineries to produce unleaded, low-sulfur gasolines and also to desulfurize all gasolines produced for United States sales.

Prior to installation of additional desulfurization process units, unleaded, low-sulfur gasolines would have to be blended from existing low-sulfur gasoline blending stocks.

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CHAPTER 2

SUMMARY

Automotive exhausts are to have catalytic mufflers for pollution control starting with the 1975 models. However, the catalysts convert the sulfur in gasoline into sulfuric acid mists in the exhaust.

This study indicates that the "typical" United States refinery can produce no-lead, low-sulfur gasoline blended from normal butane, alkylate and reformate. The predicted sales percent of no-lead and premium gasolines can be met for 1975 and 1976 with the total gasoline production meeting the EPA phase-down of lead antiknock additives. New desulfurization and octane upgrading facilities would have to be onstream by 1977 to produce the required sales percent of both no-lead, low-sulfur gasoline and premium gasoline.

The total gasolines could be made low sulfur by hydrodesulfurization of the gas oil feedstock to catalytic cracking and hydrodesulfurization of the light virgin and light thermal gasolines. Economics indicate that this scheme would add 0.74 cents per gallon to the cost of gasoline production.

An alternate case considers hydrodesulfurization of the catalytically cracked gasoline rather than the feedstock to the catalytic cracker. Economics indicate that use of this scheme to produce low-sulfur gasoline would add 0.95 cents per gallon to the cost of gasoline production. This cost includes a penalty of 0.33 cents per gallon debited to the lower octane resulting from partial hydrogenation of olefins in the FCC gasoline.

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CHAPTER 3

DISCUSSION

GENERAL REFINERY SITUATIONS

No two crude oils or two refineries are the same. Furthermore, no two refineries will produce and have the same product demand. Depending upon the crude properties and refinery process capabilities, different refineries are geared to the following categories or combinations thereof:

Productions of gasolines, mid-distillates and residual oil.

Petrochemical production.

Lubricant production.

Asphalt production.

In crude topping and vacuum operations, crude oils can be distilled into fractions with true boiling cut points approximately as follows:

Butanes and lighter components to gas recovery.

Pentanes to 200° F light gasoline for blending to gasoline or isomerization of the pentanes and hexanes to upgrade the octane number.

200 °F - 350° F naphtha for reformer feedstock to upgrade the octane number or produce aromatics.

350 °F - 500° F kerosine for production of aviation jet turbine fuel and kerosine or for blending to diesel fuel or No. 2 fuel oil.

600 °F - 1,000° F gas oil feedstock to catalytic cracking, thermal cracking or hydrocracking.

Heavier than 1,000 °F residuum for blending No. 6 fuel oil or to asphalt or produced as feedstock for visbreaking, delayed coking, fluid coking or solvent deasphalting.

Typical ASTM distillations of refined products to sales are shown in Figure 1-1. Gasolines distill in the range of 80° F to 400° F, kerosine and jet fuel (kerosine-type) distill in the range of 340° F to 530° F, and diesel fuel and No. 2 fuel oil distill in the range of 350 °F to 650° F.

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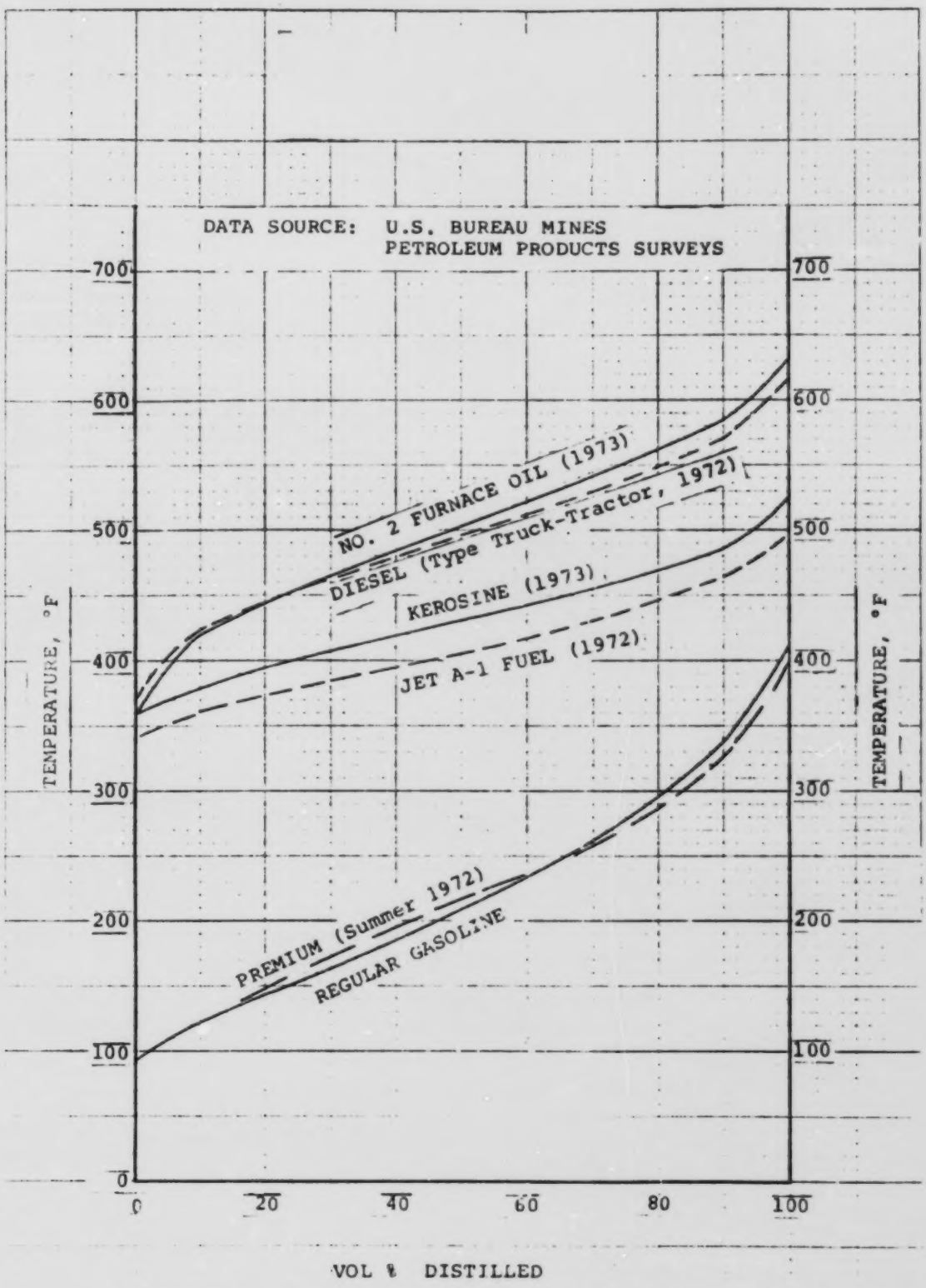

Figure 1-1. Typical ASTM distillations of petroleum products.

U.S. PRODUCTION OF PETROLEUM PRODUCTS

United States refineries produce petroleum products in relation to the market demands for quantities and properties.. Each refinery bases its operations on market demands and availability of crudes within the limitations of its refinery process units and the flexibility of operating conditions.

Table 1-1 shows the U.S. production of petroleum products in 1972. Table 1-2 shows the U.S. demand of mid-distillates by use in 1973. The term "mid-distillates" refers to the distillates boiling between gasoline and No. 6 fuel oil and comprises the kerosine, aviation jet fuel, diesel fuels and No. 2 heating oil. Kerosine, aviation jet fuel and No. 1-D diesel fuel are produced from the distillates boiling between 350°F and 500° F true boiling cut points. No. 2 heating oil and No. 2-D diesel fuel are blends of essentially 50 percent of the 350°F to 500° F fraction with 50 percent of the 500°F to 600 °F fraction.

Table 1-3 shows typical properties of the petroleum products sold in the United States in 1972 and 1973.

It appears that the crude oils to supply needs in the United States above the domestic production will be supplied by the Persian Gulf countries. These crude oils have high sulfur contents and yield more residual fuel oil.

Therefore, it is expected that the sulfur content in the products will increase in the future unless additional desulfurization units are installed.

Table 1-1. U.S. PRODUCTION OF PETROLEUM PRODUCTS IN 1972

Production	Million Barrels	Yield, %*	
Gasoline from Crude	2,014	47.0	
Natural Gas Liquids to Gasoline	305	7.1	
Gasoline Content of Naphtha-type Jet Fuel	38	0.9	
	2,357		55.0
Kerosine	80	1.9	
Kerosine-type Jet Fuel	233	5.4	
Kerosine Content of Naphtha-type Jet Fuel	38	0.9	
	351		8.2
Distillate Fuel Oil	964		22.6
Residual Fuel Oil	293		6.8
Lubricants	65		1.5
Losses	5		0.1
Unaccounted	552		12.9
Crude Runs to Stills Plus Natural Gas Liquids to Gasoline	4,587		107.1
Refinery Input	**Million Barrels**		**Input, %***
Crude Runs to Stills	4,282		100.0
Natural Gas Liquids to Gasoline	305		7.1
	4,587		107.1

*Volume percent on crude input

Table 1-2. U.S. DEMAND FOR MID-DISTILLATES BY USE IN 1973

	Million Barrels		%	
Kerosine	80		6.1	
Kerosine-type Jet Fuel	233		17.6	
Kerosine Content of Naphtha-type Jet Fuel	38		2.9	
No. 1 Range Oil	15		1.1	
		366		27.7
Diesel Fuel Used on Highways	164		12.4	
Industrial Uses	50		3.8	
Oil Company Fuel	14		1.1	
Railroads	86		6.5	
Vessel Bunkering	21		1.6	
Military Uses	17		1.3	
		352		26.7
Heating Oil	509		38.5	
Gas and Electric Company Public Utility Power Plants	35		2.6	
		544		41.1
Miscellaneous and Unaccounted		60		4.5
Total Mid-distillates		1,322		100.0

Table 1-3. TYPICAL PROPERTIES OF PETROLEUM PRODUCTS

	REGULAR GASOLINE	PREMIUM GASOLINE	REGULAR GASOLINE	PREMIUM GASOLINE	TOTAL GASOLINE POOL	KEROSINE	JET A-1 FUEL	DIESEL FUEL (DIESEL / DIESEL)	NO. 2 FURNACE OIL	NO. 6 FUEL OIL
U.S. Bureau Mines Survey	Summer 1972	Summer 1972	Winter 1972-73	Winter 1972-73	Average 1972	1973	1972	[illegible]	1973	197
Gravity, °API	60.5	60.7	62.5	63.0	61.7	42.3	42.4	[illegible]	35.1	11.0
Distillation, ASTM, °F										
IBP	92	91	84	84		341		[illegible]	[illegible]	
10	122	125	108	109		378	362	427	425	
30	163	172	150	158						
50	208	217	200	209		428	405	495	504	
70	262	257	257	251						
90	330	324	334	352		486	464	574	589	
EP	411	401	405	367		525		635	638	
Sulfur, wt %	0.047	0.026	0.030	0.023		0.067	0.065	0.21	0.22	1.89
Aniline Point, °F						146	140	147	144	
Octane Number								45.6		
Viscosity, CS at 100°F						1.66		2.71	2.71	
Viscosity, Furol at 122°F										170
Carbon Residue, wt %										9.5
Lead, g/gal	2.04	2.52	1.80	2.34						
Octane Number										
Research	94.1	99.8	93.9	99.6						
Motor	86.4	92.2	86.4	92.2						
(Research + Motor)/2	90.3	96.0	90.2	95.9						
Reid Vapor Pressure	9.2	9.3	12.2	12.1						
Total Gasoline										
Sales, %	38	62	37	63						
Sulfur, wt %	0.032		0.029		0.031					
Research Octane	97.6		97.5		97.5					
Motor Octane	90.0		90.1		90.0					
(Research + Motor)/2	93.8		93.8		93.8					
Lead, g/gal	2.34		2.14		2.24					
Reid Vapor Pressure					10.7					

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UNLEADED GASOLINE

The Environmental Protection Agency has issued regulations (Jan. 10, 1973) on unleaded gasoline (minimum 91 research octane) to be supplied starting in July, 1974.

Unleaded gasoline to be used in automobiles equipped with catalytic converters is to be generally available in United States.

General Motors announced plans to equip all its 1975 models with converters, compared to about 60 percent for Ford. Thus about 80 percent of the 1975 automobiles will have catalytic converters.

Figure 1-2 shows predicted future sales percent of unleaded and premium gasolines.

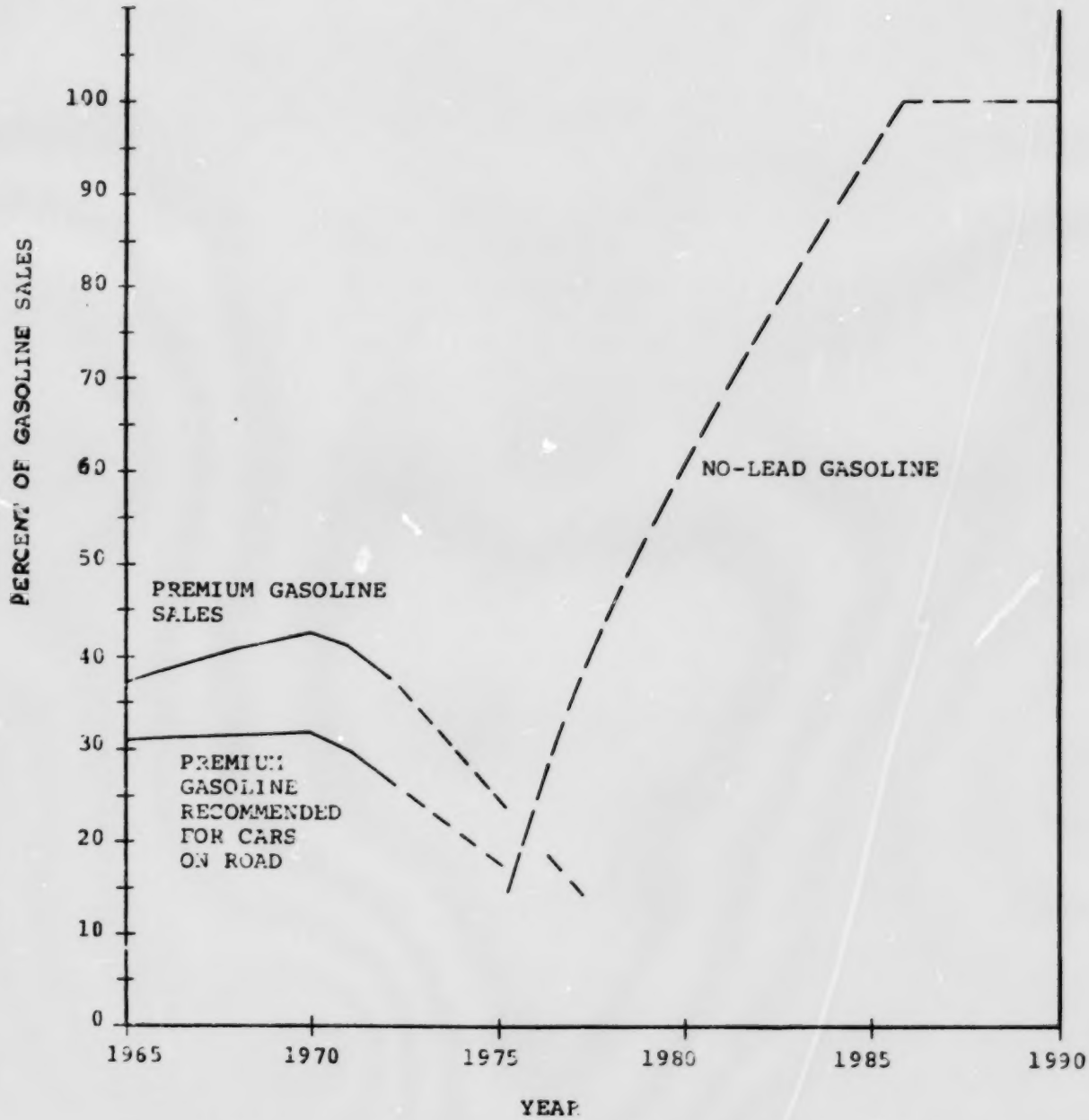

Figure 1-2. Projected percent of sales of premium and no-lead gasolines.

PHASE-DOWN OF LEAD IN GASOLINE

The Environmental Protection Agency has ordered a phased reduction of lead antiknock additives in gasoline (Federal Register, Dec. 6, 1973). These regulations restrict the average lead content in all grades of gasoline (including unleaded gasoline) produced by any refinery as follows:

January 1	Lead Content Grams per Gallon
1975	1.7
1976	1.4
1977	1.0
1978	0.8
1979	0.5

OCTANES OF TOTAL U.S. GASOLINES

The 1972 properties of the total U.S. gasoline pool were estimated from U.S. Bureau of Mines surveys and Ethyl Corporation sales data as follows:

Research Octane	97.5
Motor Octane	90.0
Lead, g/gal.	2.24
Sulfur, wt%	0.031

The response of lead content in the total U.S. gasoline pool was estimated from the lead response of various premium and regular gasoline blends. Figure 1-3 shows the research and motor octanes of the total U.S. gasoline pool in 1972 as a function of lead content.

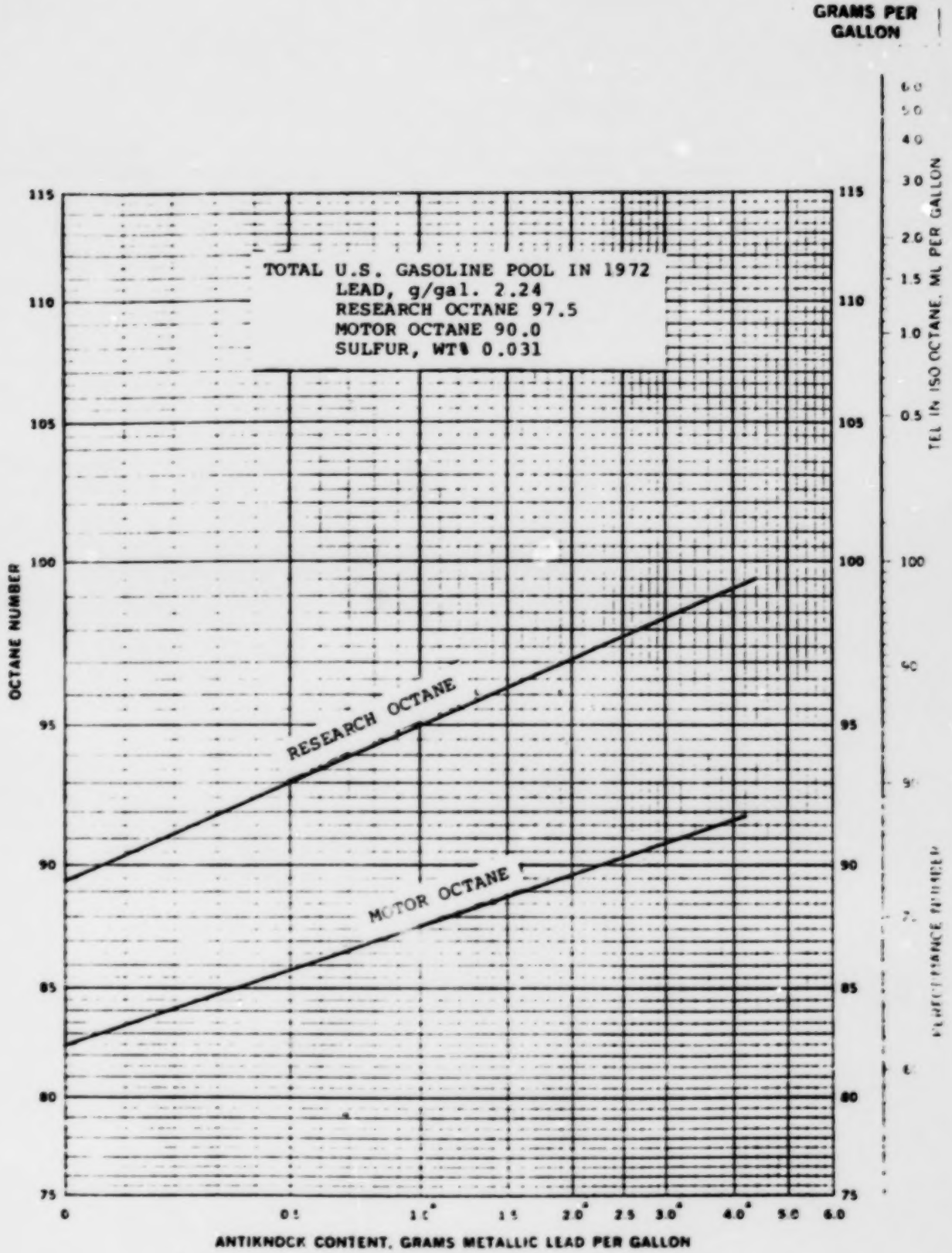

Figure 1-3. Octane of total U.S gasoline pool in 1972.

SULFUR IN GASOLINE BLENDING COMPONENTS

The sulfur contents of various light straight gasolines are shown in Table 1-4, and the sulfur contents in miscellaneous samples of other gasoline blending components are shown in Table 1-5.

The sulfur content is variable and depends upon the crude source for catalytically cracked gasoline, light straight-run gasoline, natural gasoline and coker or thermal gasoline.

Reformate and alkylate can be considered sulfur-free. The bi-metallic reformer catalyst requires that the feed naphtha be de-sulfurized to less than 1.0 ppm sulfur. The feedstocks to alkylation are desulfurized or essentially sulfur-free. In alkylation, the hydrofluoric acid catalyst or sulfuric acid catalyst quantitatively removes sulfur.

Therefore, production of sulfur-free gasoline generally will require the desulfurization of the thermally cracked gasoline, catalytically cracked gasoline and light straight-run gasoline.

Desulfurization of the gas oil feedstock to catalytic cracking will produce catalytically cracked gasoline with low sulfur content.

Table 1-4. SULFUR IN LIGHT VIRGIN GASOLINES*

Crude Source	Sulfur, WT % In Light Gasoline
East Texas	0.01
West Texas Intermediate Sweet	0.038
Ellenberger (Texas)	0.01
West Texas (0.31 wt % sulfur in crude)	0.01
West Texas Sour	0.15
Oklahoma City	0.011
Tinsley (Mississippi)	0.006
Corning (Ohio)	0.060
South Louisiana	0.006
Kuwait	0.006
Light Arabian (Saudi Arabia)	0.02
Light Iranian (Iran)	0.01

*C_5 - 200°F TBP

Table 1-5. SULFUR IN GASOLINE BLENDING COMPONENTS

Gasoline Blending Components*	Sulfur, WT %
Catalytically Cracked Gasoline	0.055
	0.036
	0.034
	0.07
	0.327
	0.039
	0.175
Alkylate	0.001
	0.008
	0.002
	0.003
Catalytic Reformate	0.001
	0.007
	0.013
	0.006
	0.002
Coker Gasoline	0.089
	0.19
	1.43
	0.59
Natural Gasoline	0.008
	0.010
	0.027

* Analyses of miscellaneous samples

PRODUCTION OF NO-LEAD, LOW-SULFUR GASOLINE WITHOUT NEW FACILITIES

The time to plan, finance and construct refining facilities to upgrade gasoline blending components requires two to three years from the date of a firm decision to proceed.

During the period until the additional gasoline upgrade facilities are onstream, the no-lead, low-sulfur gasolines will have to be blended from low-sulfur components which can be produced in the present refining facilities.

The potential production of gasolines with the EPA phase-down of lead is shown in Table 1-6. Alkylate and reformate are the high-octane components and are components in both the unleaded and premium gasolines. The gasoline blends shown in Table 1-6 are based on the yields and properties from "A" Refinery (Case I). The unleaded gasoline would be sulfur-free, since the blend consists of normal butane, alkylate and reformate. Comparison of the results in Table 1-6 with the projected percent of sales indicates that the present day refineries could produce the required sales percent of unleaded and premium gasolines in 1975 and 1976. New desulfurization and new octane upgrading facilities would have to be onstream by 1977 to produce the required sales percent of both no-lead, low-sulfur gasoline and premium gasoline.

Table 1-6. POTENTIAL GASOLINE PRODUCTION
WITH LEAD PHASE-DOWN (1)

Year	1972	1975	1976	1977	1978	1979
Lead Content, g/gal.						
Allowed by EPA	4.2(2)	1.7	1.4	1.0	0.8	0.5
Total Gasoline Pool	2.2	1.3	1.3	0.7	0.7	0.65(3)
Premium Gasoline	2.4	2.5	3.0	3.0	-	-
Regular Gasoline	1.9	1.2	1.4	1.3	1.2	0.65
Potential Gasoline, vol %						
Unleaded (92 RON)	-	18	30	40	44	(3)
Premium (100 RON)	37	26	21	6	(3)	(3)
Regular (94 RON)	63	56	49	54	56	100
Unleaded Gasoline, vol %						None
N-Butane		14.2	14.2	14.2	14.2	
Alkylate		39.5	39.5	39.5	39.5	
Reformate		46.3	46.3	46.3	46.3	
Premium Gasoline, vol %					None	None
N-Butane		14.2	11.9	11.9		
Alkylate		39.5	25.5	25.5		
Reformate		46.3	29.4	29.4		
FCC Gasoline		-	33.2	33.2		
Regular Gasoline, vol %						
N-Butane		7.3	7.3	7.3	7.3	10.3
Light Virgin Gasoline		14.4	16.6	16.6	14.4	8.1
Light Coker Gasoline		2.0	2.4	2.4	2.0	1.2
FCC Gasoline		76.3	73.8	73.8	76.3	43.1
Alkylate						17.1
Reformate						20.2

(1)Based on gasoline yields and properties from "A" Refinery (Case 1). Unleaded gasoline to be low-sulfur.

(2)Prior to EPA regulation.

(3)EPA regulation on lead content precludes production of unleaded and premium gasolines if total gasoline pool requirements are to be met.

CHAPTER 4

DESULFURIZATION OF GASOLINE

CASE 1: TYPICAL "A" REFINERY

As a basis of comparison, a "typical" United States refinery and crude mix were selected to produce about the same distribution and properties of gasolines, mid-distillates and No. 6 fuel oil (Bunker "C") as the United States production in 1972.

The refinery feedstock was considered to be a 32 API crude oil containing 0.51 weight percent sulfur. For calculations, the crude mix was considered to be 90 percent South Louisiana and 10 percent Kuwait.

The refinery process units selected were as follows:

Crude and Vacuum Distillation
Catalytic Reformer with Hydrogen Pretreat Section
Fluid Catalytic Cracker with Vapor Recovery
Delayed Coker
Alkylation
Sulfur Recovery.

Figure 1-4 is a block flow diagram showing the yields and properties of the intermediate and final product streams. Case 1 is based on 100,000 barrels per calendar day (BPCD) of crude oil. Thus, the volume percent yields based on crude oil may be obtained by dividing the BPCD flows by 1,000. The sulfur from the crude oil is shown distributed in the product streams, recovered sulfur and emissions to the atmosphere.

Table 1-7 shows a comparison of the product yields and product properties for Case 1 with the 1972 U.S. production. The distribution of yields in Case 1 shows more gasolines and mid-distillates. This may be explained by the 13.4 percent unaccounted in the 1972 U.S. production. The properties of the products show general agreement between Case 1 and the 1972 U.S. production.

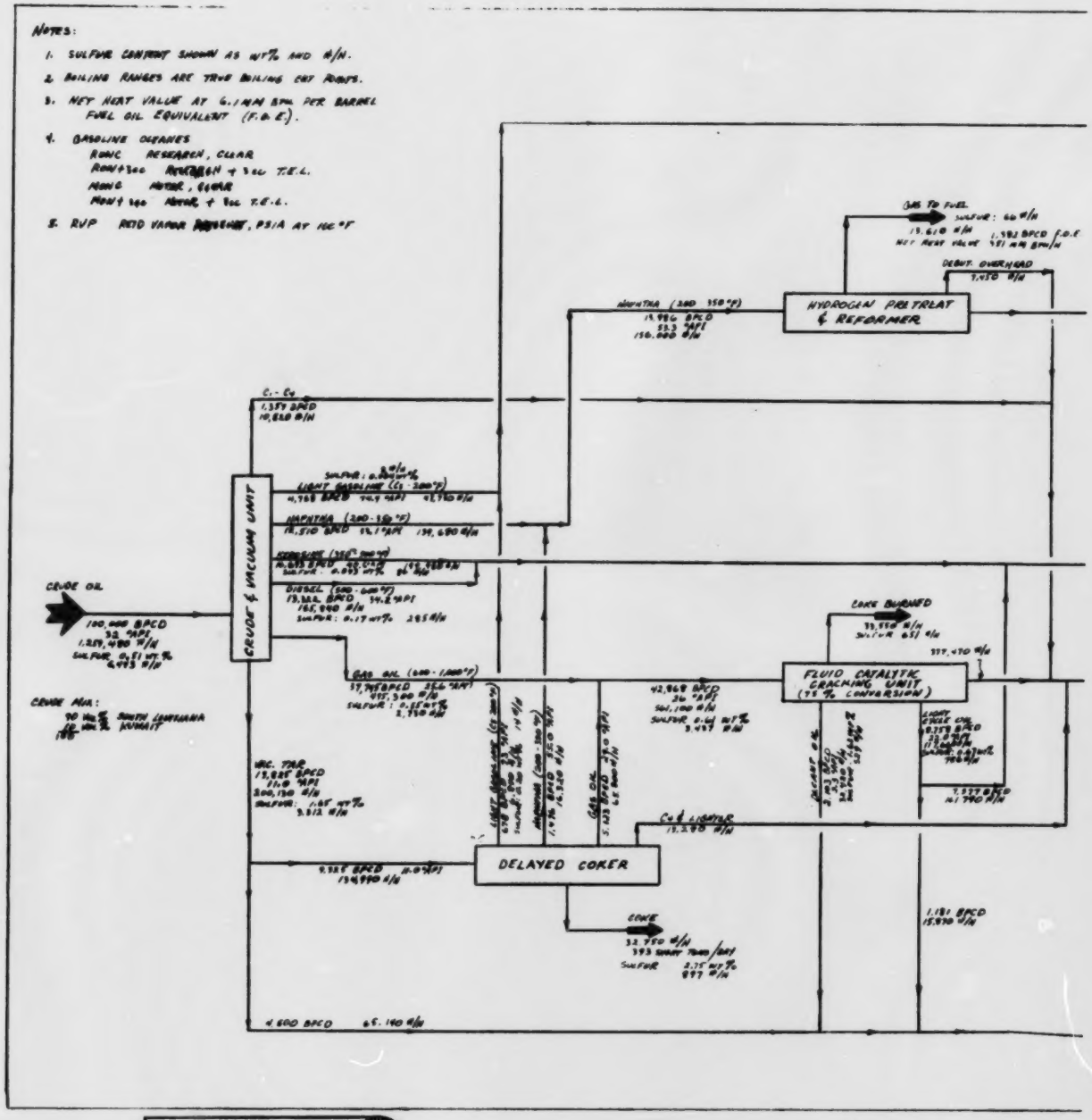

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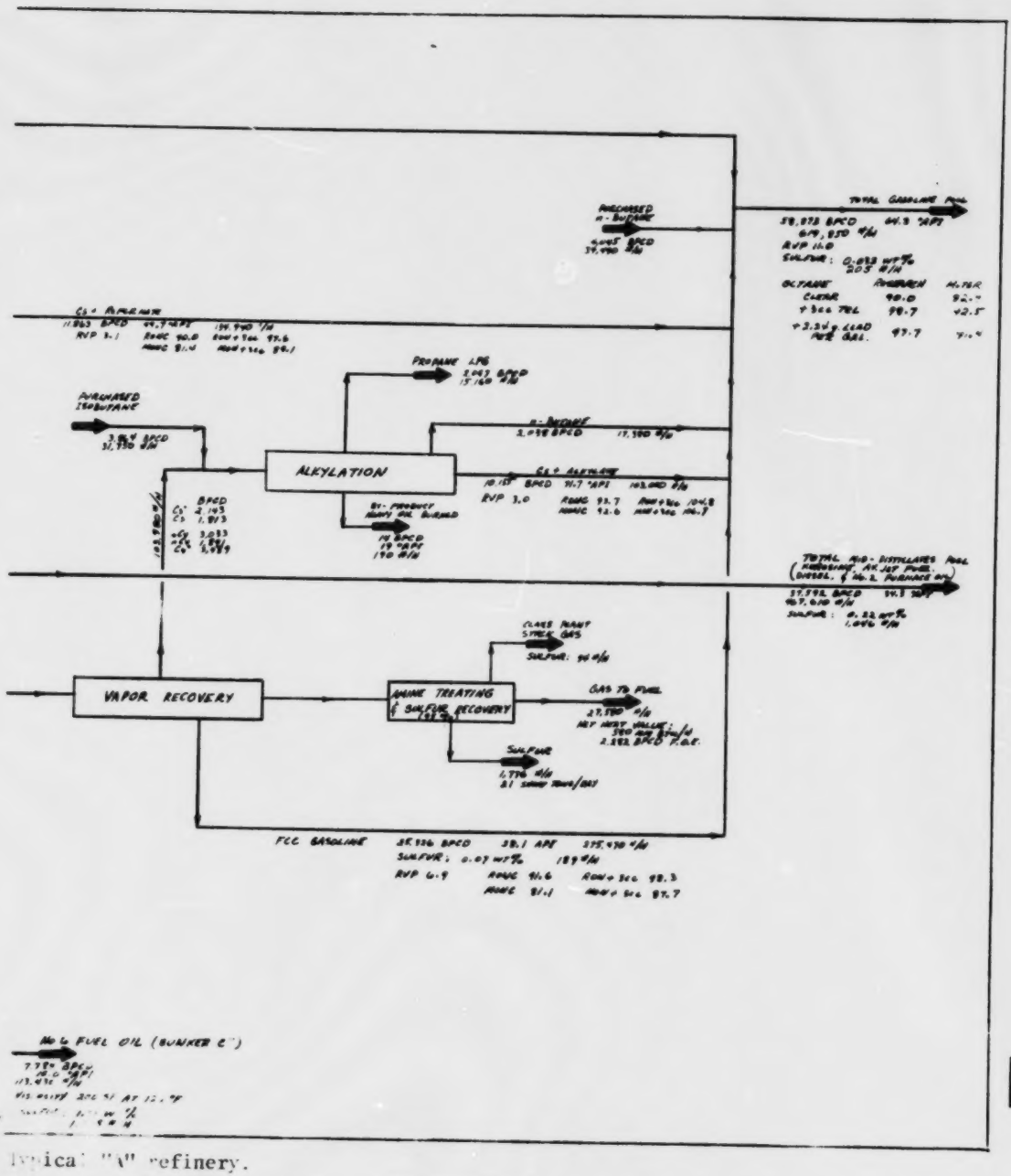
Figure 1-4. Case 1:



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25

Typical "A" refinery.

CASE 2: "A" REFINERY WITH HYDRODESULFURIZATION OF CATALYTIC CRACKER FEED, LIGHT VIRGIN GASOLINE AND LIGHT COKER GASOLINE

In order to calculate the costs of producing sulfur-free gasoline, hydrodesulfurization of the gas oil feedstock to catalytic cracking and hydrodesulfurization of the light virgin and light coker gasolines were considered. In Case 1, the sulfur content in the light virgin gasoline would be 0.004 weight percent. The light virgin gasolines listed in Table 1-4 show higher sulfur content. Therefore, hydrodesulfurization of light virgin gasoline should be included in the "typical" refinery for cost purposes.

The refinery process units in Case 2 would be the same as in Case 1 with the following additions:

Gas Oil Hydrodesulfurization
Light Gasoline Hydrodesulfurization
New Capacity for Amine Treating and Sulfur Recovery.

Figure 1-5 is a block flow diagram of Case 2 showing the yields and properties of the intermediate and final product streams. The yields and product properties also are listed in Table 1-7.

For gas oil desulfurization, the calculations are based on 80 percent sulfur removal with a hydrogen consumption of 42 standard cubic feet per pound sulfur removed (3.5 mols hydrogen consumed per mol sulfur removed). Above 85 percent sulfur removal, the hydrogen consumption increases due to saturation of polyaromatics and hydrocracking.

In Case 2, the hydrogen produced in the reformer would be more than adequate to supply the refinery needs.

The sulfur content would be 0.008 weight percent in the total gasolines.

Economics for producing low-sulfur gasoline in Case 2 are summarized in Table 1-8. Based on payout of the investment for the desulfurization units in five years (20 percent rate of return), the total added costs (above Case 1) would be about 0.74 cents per gallon of low-sulfur gasoline.

The economic basis is presented in the Appendix.

Table 1-9 shows the estimated investment for the desulfurization facilities in Case 2. Table 1-10 shows a comparison of yields in Case 1 and Case 2. Table 1-11 shows the estimated utilities and catalyst replacement cost in Case 2.

The apparent liquid gain in products over charges for Case 2 is 379 BPCD above Case 1. However, the utilities for the desulfurization facilities would require 584 BPCD of fuel equivalent. Thus, Case 2 would show a net loss of 205 BPCD in comparison to Case 1.

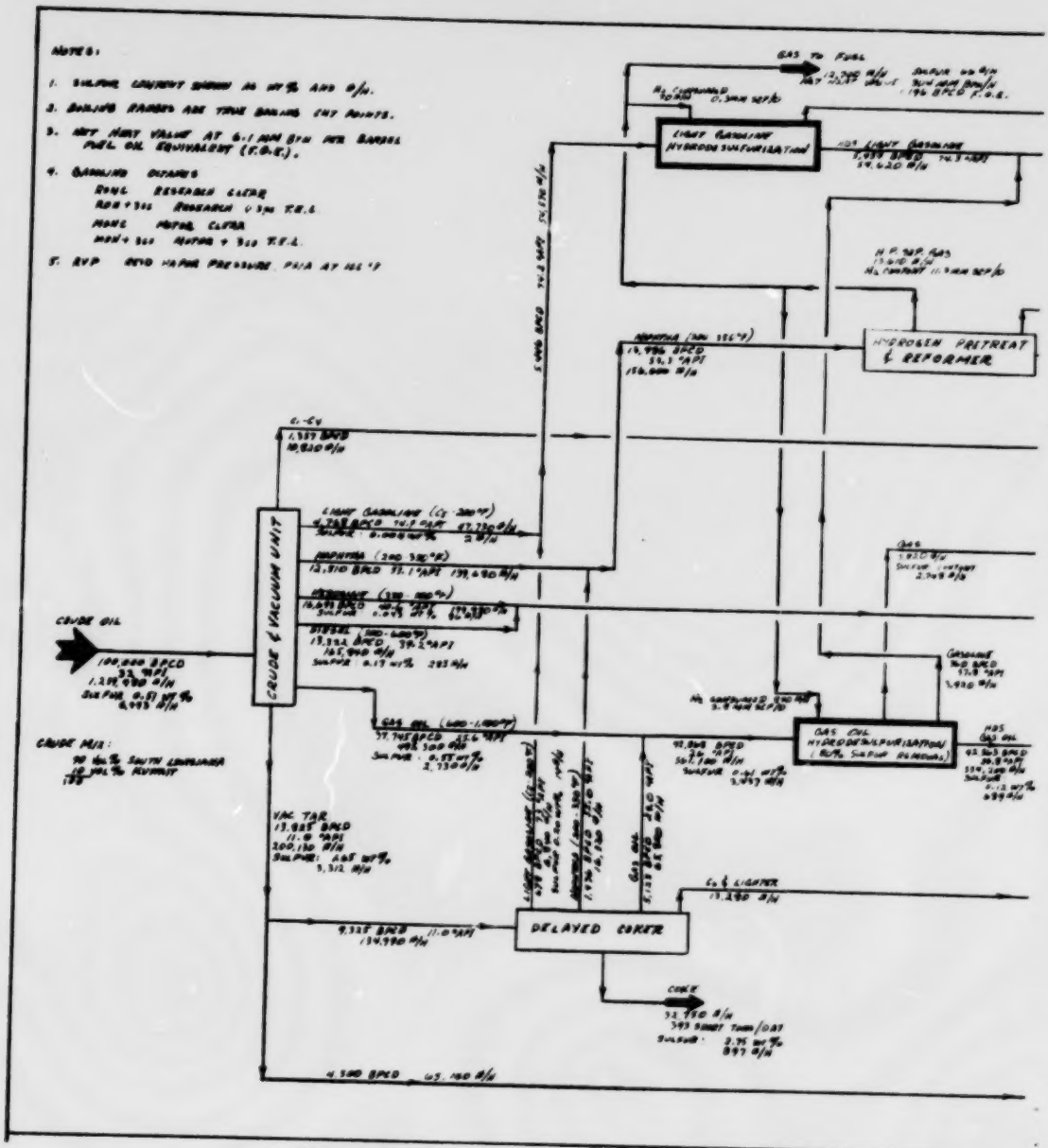

Figure 1-5. "A" refinery with hydrodesulfurization of cata-

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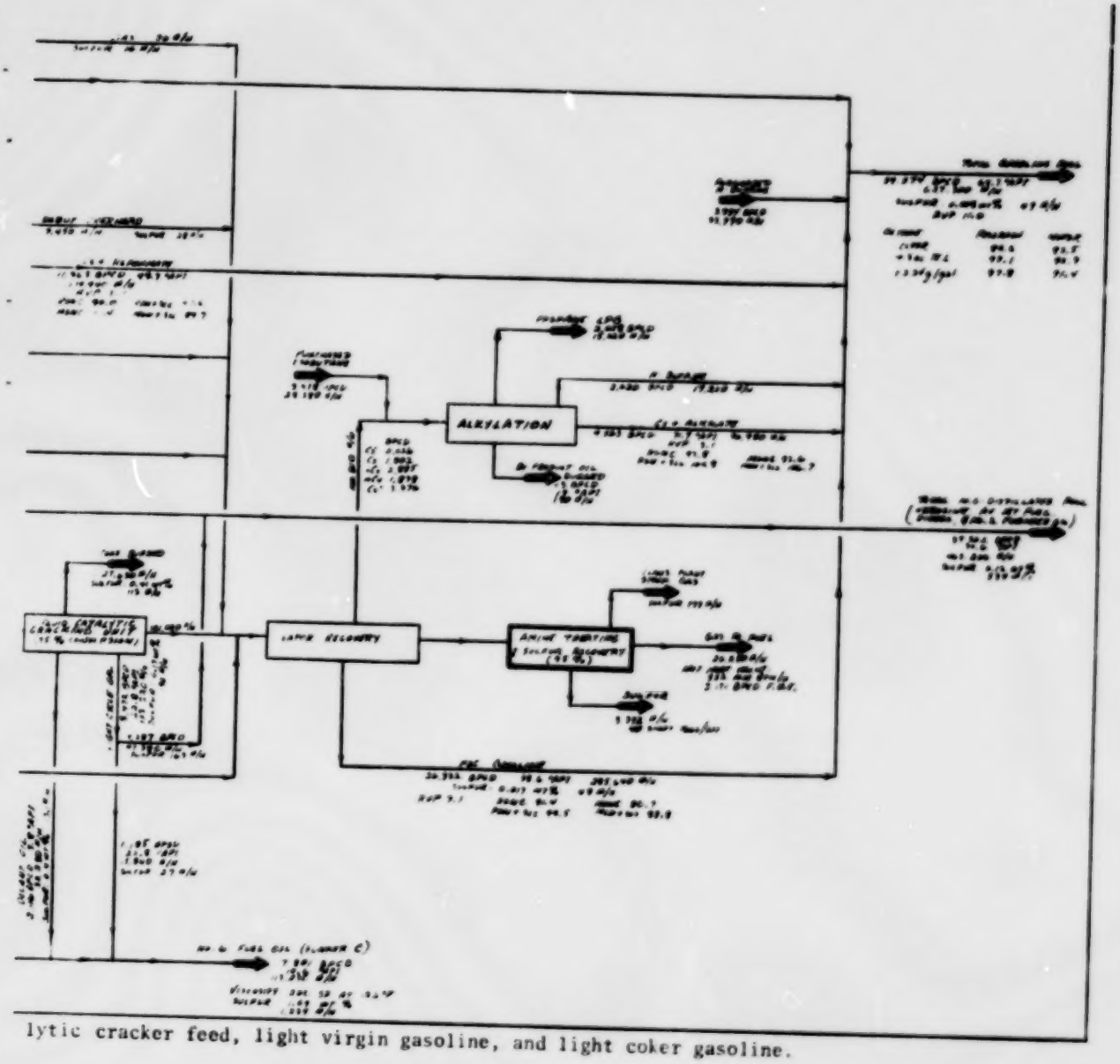

lytic cracker feed, light virgin gasoline, and light coker gasoline.

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Table 1-7. COMPARISON OF PRODUCTS

	1972 U.S. Production	Case 1	Case 2	Case 3
Total Gasolines				
Yield, vol %*	55.0	58.8	59.6	59.1
°API	61.7	64.2	64.3	64.8
Sulfur, wt %	0.031	0.033	0.008	0.007
Octanes:				
Research Clear		90.0	89.6	88.0
Research +3 cc		98.7	99.1	97.8
Motor Clear		82.9	82.5	82.1
Motor +3 cc		92.5	92.9	93.0
Research +2.24 g/gal.	97.5	97.7	97.8	96.7
Motor +2.24 g/gal.	90.0	91.4	91.4	91.8
Reid Vapor Pressure	10.7	11.0	11.0	11.0
Middle Distillates				
Yield, vol %*	30.8	37.6	37.3	37.6
Kerosine and Kerosine-type Jet Fuel				
Yield, vol %*	8.5	8.4	8.4	8.4
°API	42.3	41.0	41.0	41.0
Sulfur, wt %	0.066	0.041	0.041	0.041
Diesel Fuel				
Yield, vol %*	8.2	8.4	8.4	8.4
°API	36.5	37.3	37.3	37.3
Sulfur, wt%	0.21	0.19	0.19	0.19
No. 2 Furnace Oil				
Yield, vol %*	12.7	20.8	20.5	20.8
°API	35.1	30.5	31.0	30.5
Sulfur, wt%	0.22	0.31	0.11	0.31
No. 6 Fuel Oil				
Yield, vol %*	6.8	7.8	7.8	7.8
°API	11.0	10.0	10.6	10.0
Sulfur, wt %	1.6	1.5	1.1	1.5
Viscosity, Furol at 122°F	170	200	200	200
Carbon Residue, wt %	9.3	7.5	7.5	7.5
Miscellaneous Yield, vol %*				
Lubricants	1.5			
Delayed Coke (wt %)	13.4	2.6	2.6	2.6
Gas to Fuel (F.O.E.)		3.7	3.4	3.5
Unaccounted and Losses				

*Yield as volume percent of crude input

Table 1-8. COSTS FOR GASOLINE DESULFURIZATION - CASE 2*

Investment for Desulfurization Facilities	$13.0 million
Years to Payout	5.0

	Million Dollars per Year	$/CD
Cash Flow (13.0/5.0)	2.60	
Depreciation	0.87	
Net Profit	1.73	
Income Tax	1.73	
Gross Margin	3.46	
Operating Costs:		
Depreciation	0.87	
Operating Manpower	0.22	
Utilities	1.40	3,840
Catalyst Replacement	0.28	760
Interest	0.65	
Maintenance	0.46	
Local Taxes and Insurance	0.20	
Debit for Products (Case 1 - Case 2)	0.18	480
Credit for Lower Butane Charges	(-0.94)	(-2,570)
Total Operating Costs	3.32	
Total Added Cost for Low-sulfur Gasoline	6.78	18,580
	(0.74 cents per gallon)	

*Compared to Case 1

Table 1-9. INVESTMENT FOR PROCESS UNITS - CASE 2

Process Unit	Capacity	Investment, Million Dollars
Light Gasoline Hydrodesulfurizer	5,700 BPSD	2.6
Gas Oil Hydrodesulfurizer	45,000 BPSD	6.5
Sulfur Recovery (Claus Plant)	Two 20 TPD Units	0.9
Onsite Subtotal		10.0
Offsite at 30 percent of Onsite		3.0
Total Investment		13.0

[a] Investment includes paid-up royalty (if applicable) plus initial charge for catalyst.

Table 1-10. COMPARISON OF YIELDS - CASE 1 AND CASE 2

	BPCD		
CHARGES	CASE 1	CASE 2	DIFFERENCE
Crude Oil	100,000	100,000	-
Isobutane	3,864	3,478	(-386)
N-Butane	4,065	3,984	(-81)
Total Charges	107,929	107,462	(-467)
PRODUCTS			
Fuel Gas, F.O.E.	3,664	3,167	(-497)
Propane	2,047	2,028	(-19)
Gasolines	58,873	59,574	+701
Mid-distillates	37,592	37,302	(-290)
Sulfur	(21 TPD)	(40 TPD)	-
No. 6 Fuel Oil	7,784	7,801	+17
Delayed Coke	(393 TPD)	(393 TPD)	-
Total Product (Excluding Sulfur and Coke)	109,960	109,872	(-88)
Apparent Gain (Products - Charges)	2,031	2,410	+379

Table 1-11. UTILITIES AND CATALYST REPLACEMENT - CASE 2

Process Unit	Light Gasoline Hydrodesulfurization	Gas Oil Hydrodesulfurization	Sulfur Recovery	Total
			One 20 TPD Plant	
Consumption of Utilities:				
Electricity, kw	280	2,250	40	2,570
Fuel, MM Btu/hr	23.7	24.4	1.5	49.6
Cooling Water, gpm	380	2,400		2,780
Boiler Feedwater, lb/hr			5,250	5,250
Steam Consumed, lb/hr		58,000		58,000
Steam Generated, lb/hr			5,000	5,000
Net Steam Consumed, lb/hr				53,000
Cost of Utilities, $/CD				3,840
Catalyst Replacement Cost, $/CD	20	740		760
Fuel Equivalent of Utilities, BPCD (F.O.E.)				584

CASE 3: "A" REFINERY WITH HYDRODESULFURIZATION OF LIGHT VIRGIN, LIGHT COKER AND CATALYTICALLY CRACKED GASOLINES

Case 3 considers the costs to produce sulfur-free gasoline by hydrodesulfurization of the catalytically cracked gasoline rather than the feedstock to the catalytic cracker.

The refinery process units in Case 3 would be the same as in Case 1 with the following additions:

FCC Gasoline Hydrodesulfurization
Light Gasoline Hydrodesulfurization.

Figure 1-6 is a block flow diagram of Case 3 showing the yields and properties of the intermediate and final product streams. The yields and product properties also are listed in Table 1-7.

Sulfur removal from the FCC gasoline was selected to yield about the same sulfur content in the total gasolines as in Case 2.

In Case 3, the sulfur removal would be 75 percent from the FCC gasoline. At this desulfurization severity, 42 percent of the olefins in FCC gasoline would be hydrogenated, which would result in decreased research octane.

Economics for producing low-sulfur gasoline in Case 3 are shown in Table 1-12. Based on payout of the investment for the desulfurization units in five years (20 percent rate of return), the total added costs (above Case 1) would be 0.95 cents per gallon of low-sulfur gasoline. The costs include a penalty of 0.33 cents per gallon debited to the lower octanes which result from partial hydrogenation of olefins in the FCC gasoline.

Table 1-13 shows the estimated investment for the desulfurization facilities in Case 3. Table 1-14 shows a comparison of yields in Case 1 and Case 2. Table 1-15 shows the estimated utilities and catalyst replacement.

The apparent gain (difference between products and charges) for Case 3 would be 38 BPCD above the apparent gain for Case 1. The utilities for the desulfurization facilities would required 594 BPCD of equivalent fuel oil. Thus Case 3 would result in a net loss of 556 BPCD compared to Case 1.

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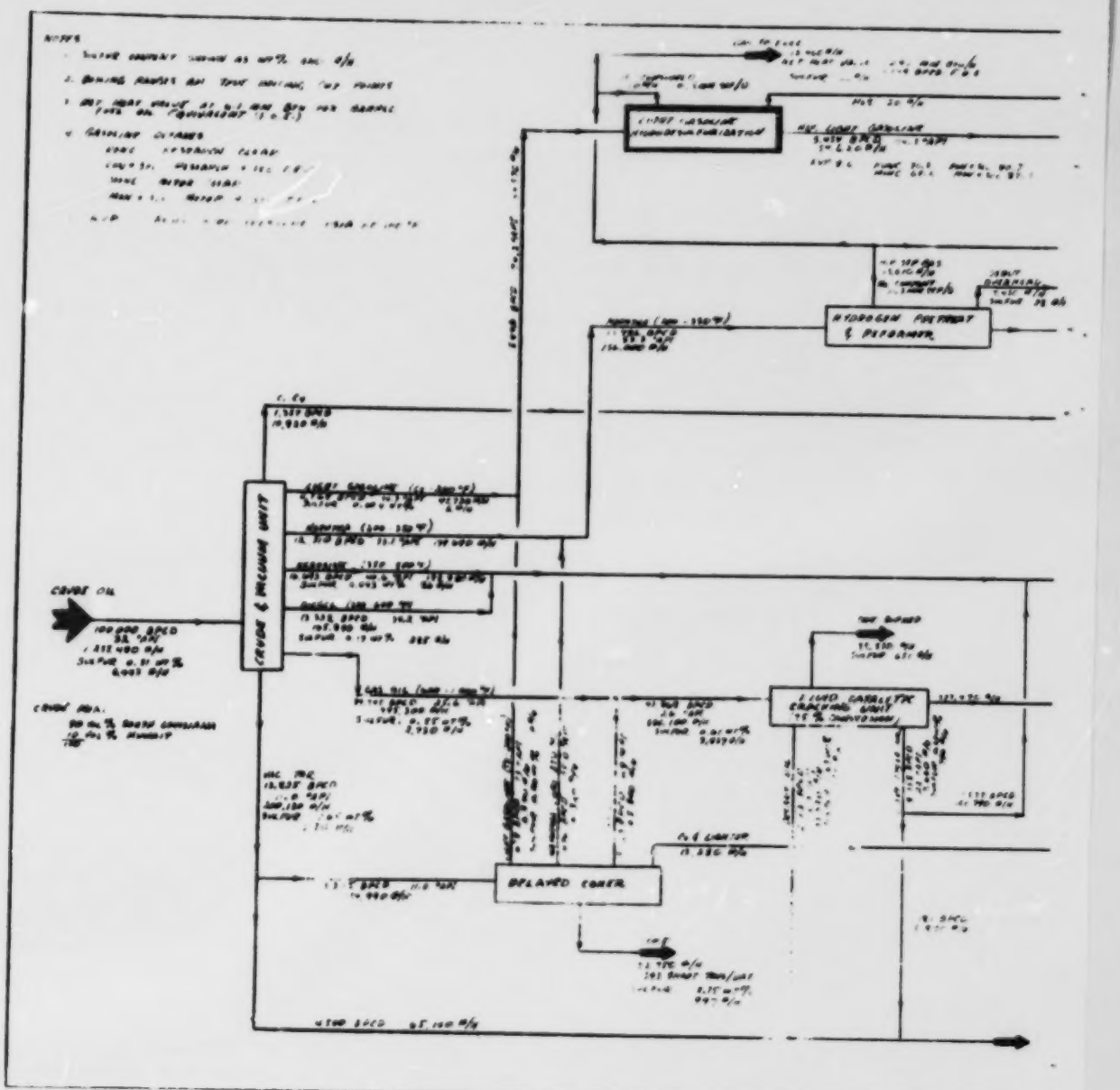

Figure 1-6. Case 3: "A" refinery with hydrodesulfurization

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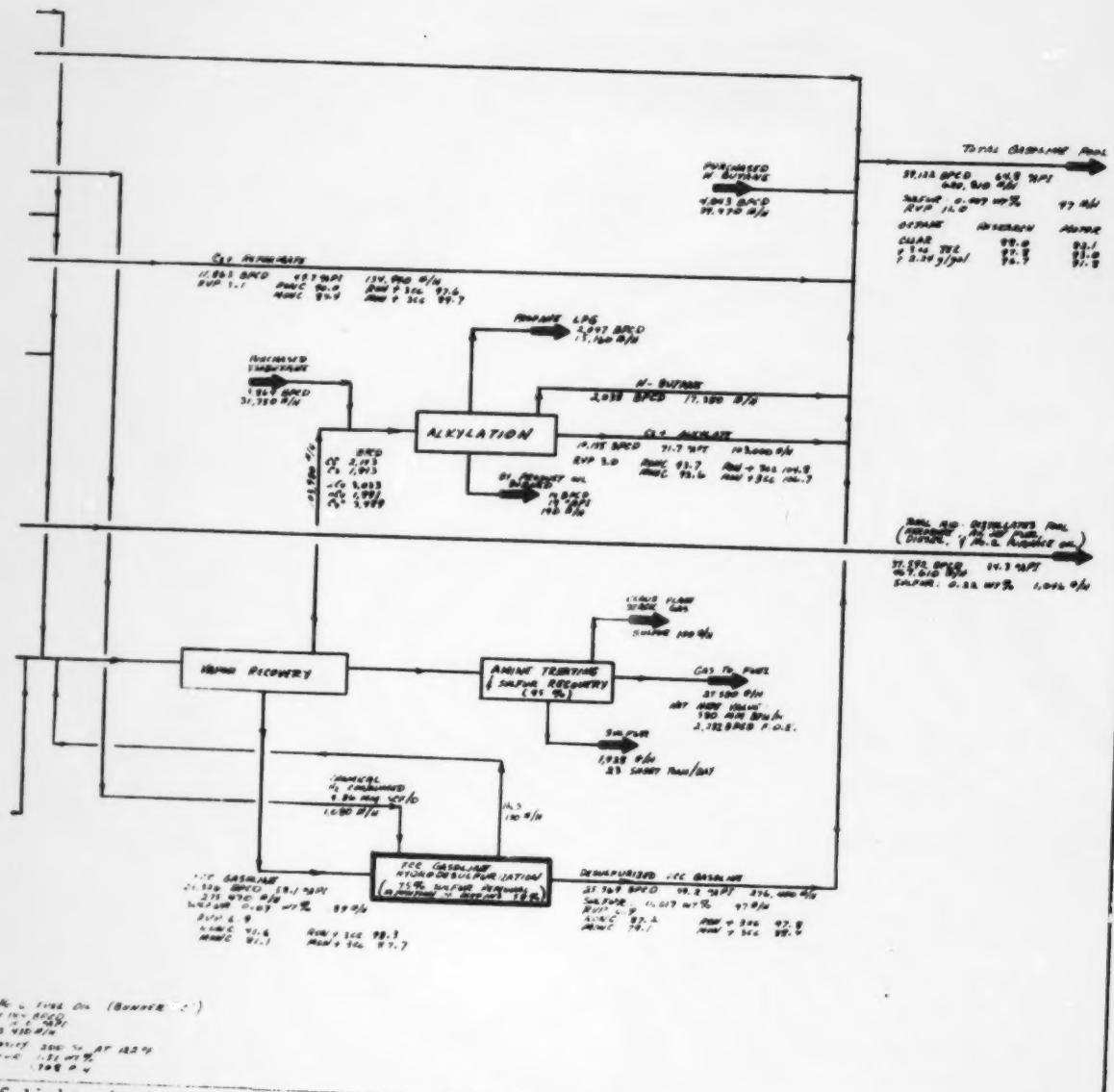

of light virgin, light coker and FCC gasolines.

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Table 1-12. COST FOR GASOLINE DESULFURIZATION - CASE 3*

Investment for Desulfurization Facilities	$9.0 million	
Years to Payout	5.0	

	Million Dollars per year	$/CD
Cash Flow (9.0/5.0)	1.80	
Depreciation	0.60	
Net Profit	1.20	
Income Tax	1.20	
Gross Margin	2.40	
Operating Costs:		
Depreciation	0.60	
Operating Manpower	0.22	
Utilities	1.43	3,920
Catalyst Replacement	0.04	100
Interest	0.45	
Maintenance	0.36	
Local Taxes and Insurance	0.14	
Debit for Lower Octane Gasoline	3.02	8,280
Credit for Lower Butane Charged	(-0.04)	(-120)
Credit for Products	(-0.03)	(-90)
Total Operating Costs	6.19	
Total Added Cost for Low-sulfur Gasoline	8.59	23,530
	(0.95 cents per gallon)	

*Compared to Case 1

Table 1-13. INVESTMENT FOR PROCESS UNITS - CASE 3

Process Unit	Capacity	Investment,* Million Dollars
Light Gasoline Hydrodesulfurizer	57,000 BPSD	2.6
FCC Gasoline Hydrodesulfurizer	26,700 BPSD	4.3
Onsite Subtotal		6.9
Offsite at 30 percent of Onsite		2.1
Total Investment		9.0

*Investment includes paid-up royalty (if applicable) plus initial charge of catalyst.

Table 1-14. COMPARISON OF YIELDS - CASE 1 AND CASE 3

	BPCD		
CHARGES	CASE 1	CASE 3	DIFFERENCE
Crude Oil	100,000	100,000	-
Isobutane	3,864	3,864	-
N-Butane	4,065	4,043	(-22)
Total Charges	107,929	107,907	(-22)
PRODUCTS			
Fuel Gas, F.O.E.	3,664	3,431	(-233)
Propane LPG	2,047	2,047	-
Gasolines	58,873	59,122	+249
Mid-Distillates	37,592	37,592	-
Sulfur	(21 TPD)	(23 TPD)	-
No. 6 Fuel Oil	7,784	7,784	-
Delayed Coke	(393 TPD)	(393 TPD)	-
Total Product (Excluding Sulfur and Coke)	109,960	109,976	(+16)
Apparent Gain (Products - Charges)	2,031	2,069	+38

Table 1-15. UTILITIES AND CATALYST REPLACEMENT - CASE 3

Process Unit	Light Gasoline Hydrodesulfurization	FCC Gasoline Hydrodesulfurization	Total
Consumption of Utilities:			
Electricity, kw	280	1,320	1,600
Fuel, MM Btu/hr	23.7	111.1	134.8
Cooling Water, gpm	380	1,770	2,150
Cost of Utilities, $/CD			3,920
Catalyst Replacement Cost, $/CD	20	80	100
Fuel Equivalent of Utilities, BPCD (F.O.E.)			594

SULFUR DISTRIBUTION

Table 1-16 shows the sulfur distribution in the products and atmospheric emission as pounds per hour sulfur and as the percent of the sulfur in the crude charge.

The sulfur in gasoline is only a small fraction of the sulfur in the crude oil charge. The final combustion of the products used as fuel including gasolines, mid-distillates and Bunker "C" results in emissions of sulfur oxides to the atmosphere. The sulfur in delayed coke may be emitted to the atmosphere or be combined in metallurgical slag, depending upon the use of the delayed coke.

Table 1-16 shows that the recovered elemental sulfur would be 27.6 percent of the sulfur in the crude oil in a "typical" refinery (Case 1) and 52.3 percent of the sulfur in the crude oil in Case 2.

Table 1-16. SULFUR DISTRIBUTION

Sulfur Content, LB/HR	Case 1	Case 2	Case 3
Crude Oil	6,443	6,443	6,443
Products:			
Gasoline	205	49	47
Mid-distillates	1,046	534	1,046
Bunker "C"	1,708	1,235	1,708
Delayed Coke	897	897	897
Recovered Elemental Sulfur	1,776	3,372	1,928
Emitted as SO_2 to Atmosphere	811	356	817
Total	6,443	6,443	6,443

Sulfur Distribution, %*	Case 1	Case 2	Case 3
Products:			
Gasoline	3.2	0.8	0.7
Mid-distillates	16.2	8.3	16.2
Bunker "C"	26.5	19.2	26.5
Delayed Coke	13.9	13.9	13.9
Recovered Elemental Sulfur	27.6	52.3	30.0
Emitted as SO_2 to Atmosphere	12.6	5.5	12.7
	100.0	100.0	100.0

* Sulfur distribution as percent of sulfur in crude charges.

APPENDIX A.

COSTS

1. All costs and capital are based on January, 1974 levels.

2. Capital related charges

   Straight-line depreciation for 15 year life.

   Interest at 10 percent per year. This is equivalent to 5 percent per year over the average payout period.

   Maintenance: onsite, 4 percent; offsite, 2 percent.

   Local taxes and insurance: 1.5 percent.

   Payout on investment: 5 years after taxes.

3. U. S. income plus state corporation taxes at 50 percent of gross profit.

4. Incremental utility costs

   Fuel: $1.00 per million Btu net heat value. This is equivalent to $5.50 per barrel of 32° API crude oil.

   Electricity:

	$ Per KWH
Fuel cost	0.010
Other charges	0.006
	0.016

   Steam: $1.40 per 1,000 pounds corresponding to the fuel cost of $1.00 per million Btu.

   Cooling water: $0.02 per 1,000 gallons circulation.

   Treated boiler feedwater: $0.05 per 1,000 pounds.

5. Operating manpower costs

   Average costs for stillman and operators at $6.00 per hour plus 30 percent fringe benefits. Sixty percent overhead on operating manpower is added to allow for supervision, laboratory, technical service and instrument services.

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5. Operating manpower costs (Contd.)

Manpower Cost Per Shift Position	$/HR	%	$/YR
Rate	6.00		52,600
Fringe Benefits		30	15,800
Overhead		60	41,000
Total			109,400

6. Product prices

Incremental product yields were priced at the same price as crude oil ($5.50 per barrel).

7. Royalties

Gas oil hydrodesulfurization:
Paid-up royalty $10.00 per BPCD feed rate.

Naphtha hydrodesulfurization:
Royalty-free. Royalty costs would be included in catalyst costs or nominal know-how fee.

8. Hydrogen make-up

Assumed to be available in the reformer make-gas for for hydrodesulfurization units.

9. Gasoline octane

Incremental gasoline octane priced at 2.0 cents per 6 octane difference between premium and regular gasolines at the 1972 lead level of 2.24 grams per gallon. This price is equivalent to 0.333 cents per gallon per research octane number.

APPENDIX B.

OIL EQUIVALENT OF UTILITIES

1. Fuel

   Net heat value at 6.1 million Btu per barrel fuel oil equivalent.

2. Electricity

   Net heat to generate electricity is assumed to be 10,000 Btu per kilowatt-hour. This requires 0.04 BPCD F.O.E. per kilowatt-hour.

3. Steam

   Net heat to generate steam is assumed to be 1,370 Btu per pound of steam. This requires 5.4 BPCD F.O.E. per 1,000 pounds per hour of steam.

APPENDIX C.

SOURCES OF INFORMATION

American Petroleum Institute

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Part 80. Regulations of Fuels and Fuel Additives
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"Yearly Report of Gasoline Sales by States, 1972"

Gulf Oil Corporation

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"Kuwait Crude Oil Handbook"

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PART 2

PRODUCTION OF LOW-SULFUR GASOLINES

(PHASE 2)

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CHAPTER 1

INTRODUCTION

This part of the report covers work which was performed under Contract No. 68-02-1308 for the Environmental Protection Agency, (EPA) Office of Research and Monitoring, Task No. 10, Phase 2.

Automobile manufacturers indicate that some automobiles will have catalytic mufflers for pollution control starting with the 1975 model year. To avoid poisoning of the catalyst, no-lead gasoline is required. The catalytic mufflers reduce emissions of carbon monoxide and hydrocarbons; however, the catalysts convert sulfur in the gasoline into sulfuric acid mist in the exhaust.

The purpose of this work is to determine the impact of producing low-sulfur gasolines on the refineries in the United States. To show the impact on U.S. refineries it was decided to select a "typical" refinery as a basis such that plant capacity, capacities of individual process units, yields of products, and properties of products about matches the average of the total U.S. refineries. Desulfurization facilities were then added to this refinery, using two process schemes, to produce low-sulfur gasolines.

The results presented herein supersede the results presented in the Phase I study.

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CHAPTER 2

SUMMARY

This study shows how a "typical" U.S. refinery can produce no-lead, low-sulfur gasoline and by installing new hydrodesulfurization facilities produce the low sulfur gasolines to include the no-lead, premium and regular gasolines.

Results of this study indicate that no-lead, low-sulfur gasoline would have to be blended from normal butane, alkylate, and reformate in the existing "typical" United States refineries. Beyond 1975, the predicted demand of no-lead (low-sulfur) and premium gasolines could not be met with the EPA limits on lead anti-knocks in the total gasoline pools.

Total gasolines could be made low sulfur by hydrodesulfurization of the gas oil feedstock to catalytic cracking and by hydrodesulfurization of the light virgin and light coker (or thermal) gasolines. Economics for this scheme (Case 2) show that the costs for producing gasoline would be increased depending upon refinery size approximately as follows:

Refinery Crude Capacity, BPCD	Desulfurization Costs, Cents Per Gallon
16,000	1.59
44,000	1.01
100,000	0.67

An alternate case considers hydrodesulfurization of the catalytically cracked gasoline rather than the feedstock to the catalytic cracker. Economics indicate that this scheme (Case 3) to produce low-sulfur gasoline would add about 0.82 cents per gallon to the cost of gasoline pro-

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duction for a 100,000 BPCD refinery. This cost includes a penalty of 0.3 cents per gallon of gasoline debited to the lower octane resulting from partial hydrogenation of olefins in the FCC gasoline.

If new facilities were installed to desulfurize all the U.S. gasolines by desulfurizing light virgin and themal gasolines and desulfurizing the cat cracker feedstock, it would require an investment of about 2.0 billion dollars by U.S. refiners based on January, 1974 costs.

Based on the gasoline yields and properties in Case 2 for low-sulfur gasolines, no-lead, premium and regular gasolines could be blended in the predicted sales volumes and the total gasoline pool could meet the EPA regulations on lead phase-down until 1979. Octane up-grading would be required in 1979 to meet the limit of 0.5 grams of lead per gallon.

"A" Typical U.S. Refinery is shown as Case 1 and conforms to the following criteria:

- Median capacity of crude charges to U.S. refineries
- Capacities of process units within the refinery about matches the average percent of crude input as the total U.S. refineries.
- The crude charge produces about the average percent yields and properties of products as the total U.S. refineries.

CHAPTER 3

EPA REGULATIONS ON GASOLINES

UNLEADED GASOLINE

Regulations by the Environmental Protection Agency (EPA) to limit the emissions of carbon monoxide and hydrocarbons require most future automobiles to have catalytic mufflers.

General Motors announced plans to equip all its 1975 models with converters, compared to about 60 percent for Ford. Thus about 80 percent of the 1975 automobiles will have catalytic converters.

Unleaded gasoline to be used in automobiles equipped with catalytic converters is to be generally available in the United States at major service stations.

The EPA has issued regulations (January 10, 1973) on unleaded gasoline (minimum 91 research octane) to be supplied starting in July, 1974.

PHASE-DOWN OF LEAD IN GASOLINE

The EPA has ordered a phase reduction of lead antiknock additives in gasoline (Federal Register, Dec. 6, 1973). These regulations restrict the average lead content in all grades of gasoline (including unleaded gasoline) produced by any refinery as follows:

January 1	Lead Content Grams per Gallon
1975	1.7
1976	1.4
1977	1.0
1978	0.8
1979	0.5

CHAPTER 4

PRODUCTION OF NO-LEAD, LOW-SULFUR GASOLINE IN PRESENT U.S. REFINERIES

DEFINITION OF "A" TYPICAL U.S. REFINERY

The purpose of this study is to determine the impact of producing low-sulfur gasolines by the refineries in the United States.

"A" Typical U.S. Refiner can be used to show the production of no-lead, low-sulfur in the present U.S. refineries and then develop the added costs to produce gasolines by installing new hydrodesulfurization facilities.

For this purpose, "A" Typical U.S. Refinery and the crude charge should conform to the following criteria:

- Median capacity of crude charges to U.S. refineries
- Capacities of process units within the refinery matches about the average percentage of crude input as the total U.S. refineries
- The crude charge produces about the average percent yields and properties of products as the total U.S. refineries

CASE 1: "A" TYPICAL U.S. REFINERY

The refinery process units selected for Case 1 were as follows:

- Crude and Vacuum Distillation
- Catalytic Reformer with Hydrogen Pretreat Section
- Fluid Catalytic Cracker with Vapor Recovery
- Delayed Coker

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- Alkylation
- Sulfur Recovery

For calculations, the refinery feedstock was considered to be a 38.4° API mixture of Texas-Louisiana crude oils containing 0.5 weight percent sulfur.

Figure 2-1 is a block flow diagram showing the yields and properties of intermediate and final product streams. Case 1 is based on 100,000 barrels per calender day (BPCD) of crude oil. Thus, the volume percent yields based on crude oil may be obtained by dividing the BPCD flows by 1,000. The vapor pressures and octanes of the gasoline component streams are shown in Figure 2-1. The sulfur in the crude oil is shown distributed in the product streams, recovered sulfur, and emissions to the atmosphere.

To simplify the work, the following conditions were assumed:

- Production of alkylate was set at 5.8 volume percent on crude input by taking propylene to LPG.
- Reformer would produce reformate with 95 research octane clear.
- Catalytic cracker would operate at 75% conversion with yields corresponding to riser cracking using zeolite catalyst.
- Unfinished asphalt would be produced from vacuum tar.
- Production of lubricants and waxes were not considered as these account for only 1.8 volume percent on crude input.

- Special naphthas and the benzene-toluene-xylenes aromatics were considered to be part of reformate and would be accounted in the total gasolines.

Comparisons of the results in Case 1 with the averages for the U.S. refineries from statistics are as follows:

- Table 2-1 - Comparison of Process Units in Case 1 with the U.S. Average
- Table 2-2 - Comparison of Products and Yields - 1972 U.S. Production vs. Typical Refineries.
- Figure 2-2 - Octane of Total Gasoline Pool - Typical Refineries

The median quantity of crude refined in the United States in 1973 was processed in refineries with a median capacity of about 100,000 barrels per stream day (BPSD) of crude oil. Capacities of refineries are usually expressed in barrels per stream or operating day (BPSD) whereas accounting of the annual production is on a barrels per calendar day (BPCD) which considers the down time.

These comparisons show that refinery and crude oil in Case 1 may be considered to be "A" Typical U.S. Refinery by conforming to the criteria stated previously in this chapter.

Further imports of foreign crudes with lower °API gravities, higher sulfur content, and higher metals content than domestic crudes will result in a somewhat different distribution of products with higher sulfur

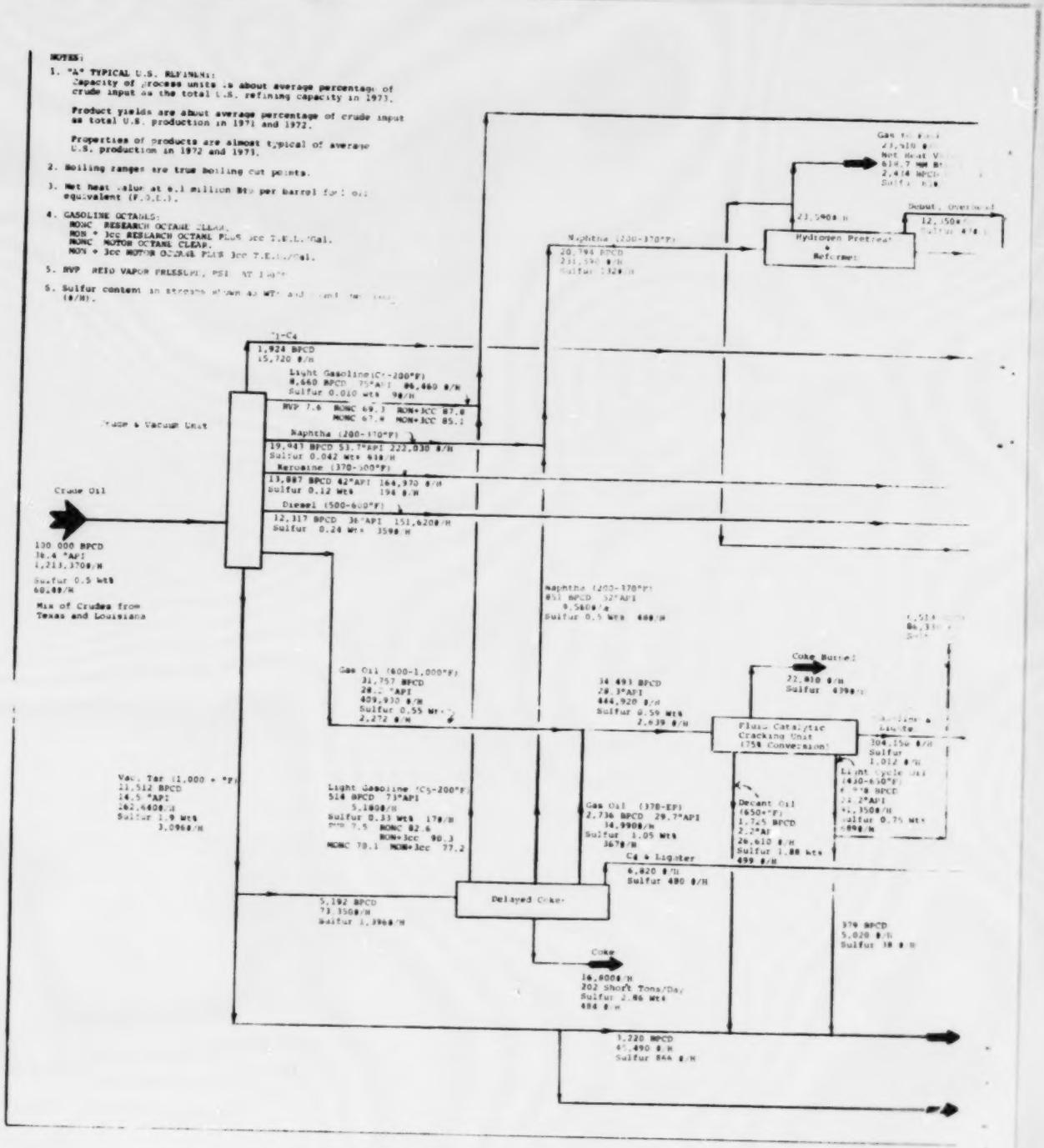

Figure 2-1. "A" typical

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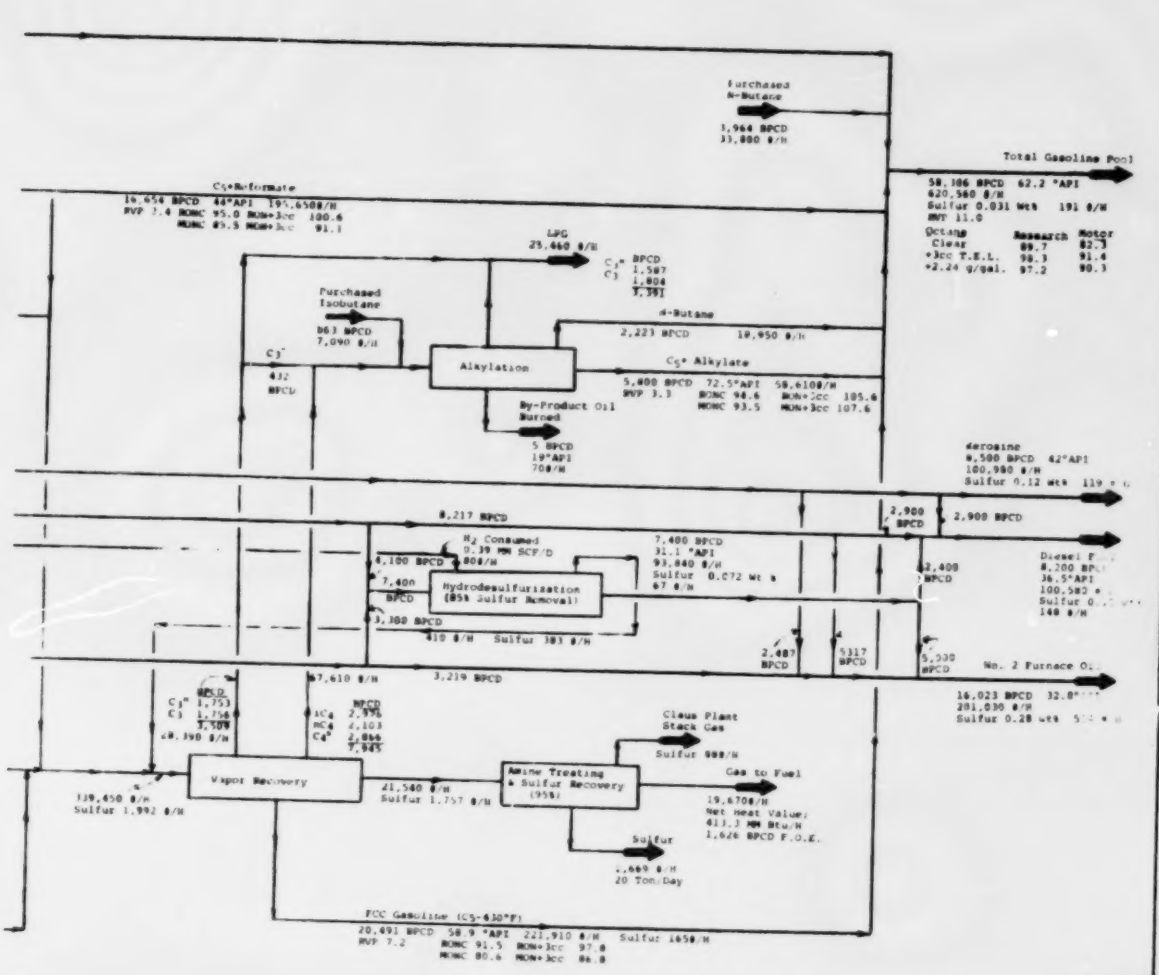

U.S. refinery (Case 1).

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Table 2-1. COMPARISON OF PROCESS UNITS IN CASE 1 WITH THE U.S. AVERAGE

Process Units	Vol. % of Crude Capacity	
	U.S. Refineries in 1973	Case 1
Crude Distillation	100.0	100.0
Vacuum Distillation	36.8	37.8*
Cokers (Delayed and Fluid)	6.4	5.2
Catalytic Cracking	32.3	34.5
Naphtha Hydrodesulfurization	20.0	20.8
Catalytic Reformer	23.4	20.8
Mid-Distillate Hydrodesulfurization	7.9	7.4
Alkylation	5.8	5.8

* At 670°F TBP cut point in crude oil.

Table 2-2. COMPARISON OF PRODUCTS AND YIELDS, 1972 U.S. PRODUCTION VERSUS TYPICAL REFINERIES

	1972 U.S. Production	Case 1	Case 2	Case 3
Total Gasolines				
Yield, vol%	58.2	58.3	58.7	58.5
°API	61.7	62.0	62.1	62.6
Sulfur, wt%	0.031	0.031	0.006	0.006
Research Clear		89.7	89.3	88.0
Research + 3cc TEL		98.3	98.9	98.5
Research + 2.24 g. lead/gal	97.5	97.2	97.8	
Motor Clear		82.3	82.2	81.7
Motor + 3cc TEL		91.4	92.2	92.3
Motor + 2.24 g. lead/gal	90.0	90.3	91.1	
Reid Vapor Pressure	10.7	11.0	11.0	11.0
Kerosine and Kerosine-Type Jet Fuel				
Yield, vol%	8.5	8.5	8.5	8.5
°API	42.3	42.0	42.0	42.0
Sulfur, wt%	0.066	0.12	0.12	0.12
Diesel Fuel				
Yield, vol%	8.2	8.2	8.2	8.2
°API	36.5	36.5	36.5	36.5
Sulfur, wt%	0.21	0.15	0.13	0.15
No. 2 Furnace Oil				
Yield, vol%	14.4	16.0	15.7	16.0
°API	35.1	32.8	33.1	32.8
Sulfur, wt%	0.22	0.28	0.14	0.28
No. 6 Fuel Oil				
Yield, vol%	6.8	5.3	5.5	5.3
°API	11.0	10.9	12.6	10.9
Sulfur, wt%	1.6	1.8	1.3	1.8
Viscosity, Furol at 122°F	170	170	170	170
Asphalt, vol% (5.5 bbl=1 short ton)	3.8	3.1	3.1	3.1
Coke, vol% (5 bbl=1 short ton)	1.5	1.0	1.0	1.0

Table 2-2.(continued) COMPARISON OF PRODUCTS AND YIELDS,

1972 U.S. PRODUCTION VS. TYPICAL REFINERIES

	1972 U.S. Production	Case 1	Case 2	Case 3
Liquefied Petroleum Gas (LPG), vol%	1.9	3.4	3.7	3.4
Still Gas to Fuel, vol%	3.8	4.1	3.9	3.9
Other Products, vol%		None	None	None
Lubricants	1.6			
Wax (1 bbl-280 lb.)	0.2			
Road Oil	0.2			
Miscellaneous	0.3			

Notes:

1. Yields are volume percent on crude input.
2. Where 1972 yields were not available, they were estimated from 1971 products. Petrochemical feedstocks (aromatics) and special naphthas added into total gasoline production.

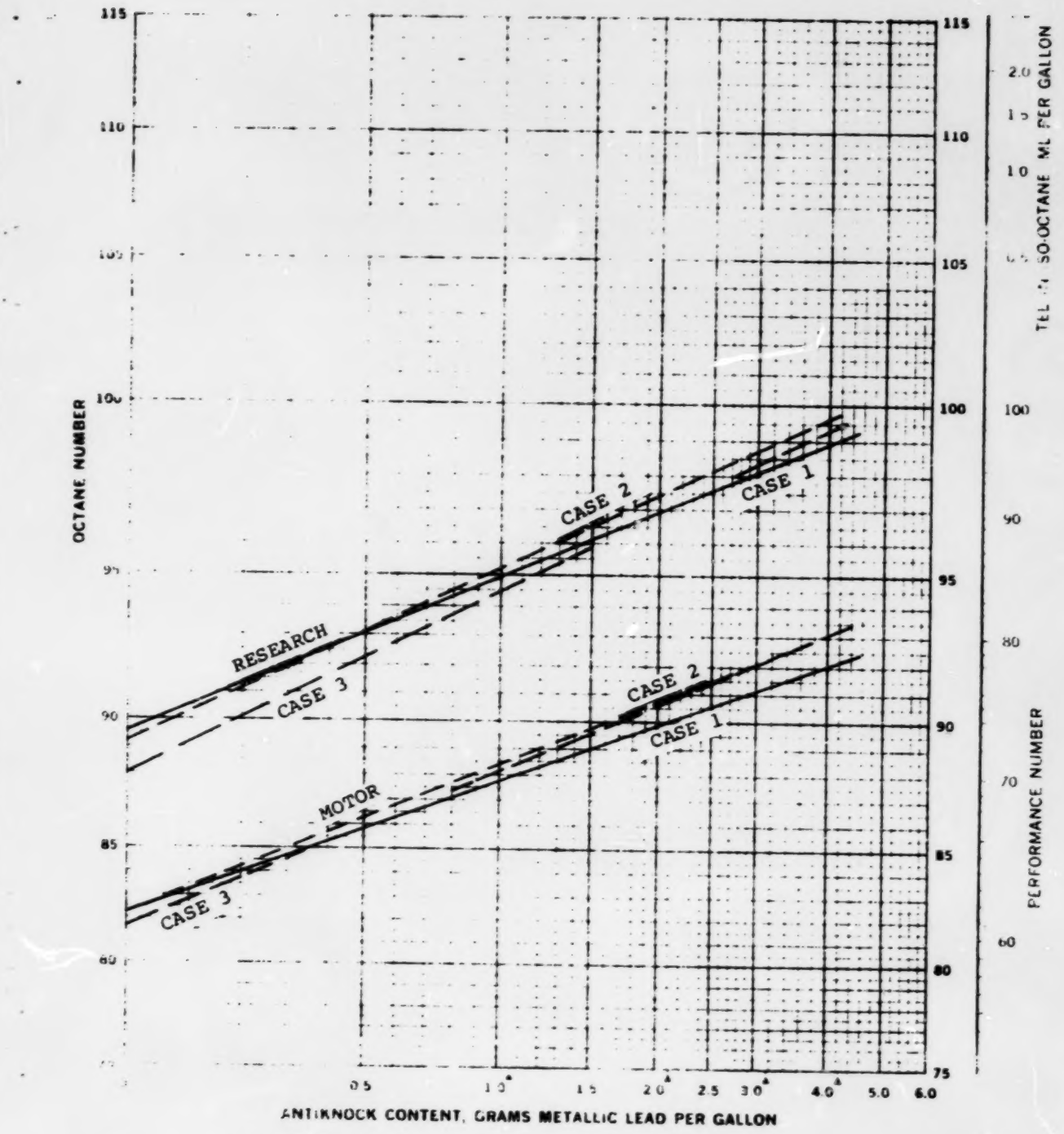

Figure 2-2. Octanes of total gasoline pool.

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content than shown in Case 1.

PRODUCTION OF NO-LEAD, LOW-SULFUR GASOLINE IN PRESENT FACILITIES

The time to plan, finance and construct refining facilities to upgrade gasoline blending components requires two to three years from the date of a firm decision to proceed. During the period until the additional gasoline-upgrade facilities are onstream, the no-lead, low-sulfur gasolines will have to be blended from low-sulfur components which can be produced in the present refining facilities.

Sulfur contents of various gasoline blending components can be shown by the analyses of various samples in Tables 2-3 and 2-4. The sulfur content is variable and depends upon the crude source for catalytically cracked gasoline, light straight-run gasoline, natural gasoline and coker or thermal gasoline.

Reformate and alkylate can be considered sulfur-free. The bi metallic reformer catalysts require that the feed naphtha be desulfurized to less than 1.0 ppm sulfur. The feedstocks to alkylation are desulfurized or essentially sulfur-free. In alkylation, the hydrofluoric acid catalyst or sulfuric acid catalyst quantitatively removes any residual sulfur.

Production of sulfur-free gasolines generally will require the desulfurization of thermally cracked gasoline, catalytically cracked gasoline, and light straight-run gasoline. However, until new desulfurization facilities are installed, the requirements for no-lead, low-sulfur

Table 2-3. SULFUR IN GASOLINE BLENDING COMPONENTS

Gasoline Blending Components*	Sulfur, WT%
Catalytically Cracked Gasoline	0.055
	0.036
	0.034
	0.07
	0.327
	0.039
	0.175
Alkylate	0.001
	0.008
	0.002
	0.003
Catalytic Reformate	0.001
	0.007
	0.013
	0.006
	0.002
Coker Gasoline	0.089
	0.19
	1.43
	0.59
Natural Gasoline	0.008
	0.010
	0.027

*Analyses of miscellaneous samples

Table 2-4. SULFUR IN LIGHT VIRGIN GASOLINES*

Crude Source	Sulfur, WT% In Light Gasoline*
East Texas	0.01
West Texas Intermediate Sweet	0.038
Ellenberger (Texas)	0.01
West Texas (0.31 wt% sulfur in crude)	0.01
West Texas Sour	0.15
Oklahoma City	0.011
Tinsley (Mississippi)	0.006
Corning (Ohio)	0.006
South Louisiana	0.006
Kuwait	0.006
Light Arabian (Saudi Arabia)	0.02
Light Iranian (Iran)	0.01

*C_5 - 200°F TBP

gasolines will have to be blended from low-sulfur blend stocks, such as n-butane, reformate and alkylate.

Starting in July, 1974 the no-lead gasoline will have to be available for the 1975 automobiles equipped with catalytic mufflers. Gasoline blending components presently available will be used to blend the no-lead, premium, and regular gasolines. In future years as more automobiles in service have catalytic mufflers and the pre-1971 automobiles are increasingly junked, more no-lead gasoline and less premium gasoline will be required to satisfy automobile needs. The 1971 and later automobiles without catalytic mufflers can use regular gasoline.

Figure 2-3 shows a projected percent of sales of premium and no-lead gasolines.

The potential production of no-lead, low-sulfur gasoline together with premium and regular gasolines was calculated attempting to meet the EPA regulations on lead phase-down using the blending components produced in Case 1. These results (Table 2-5) indicate that the projected percent of gasoline sales can be produced through 1975. In 1976 and later years the EPA limit on lead content would be exceeded. In 1977 and later years the production of no-lead, low-sulfur and premium gasolines would be less than the projected percent of sales.

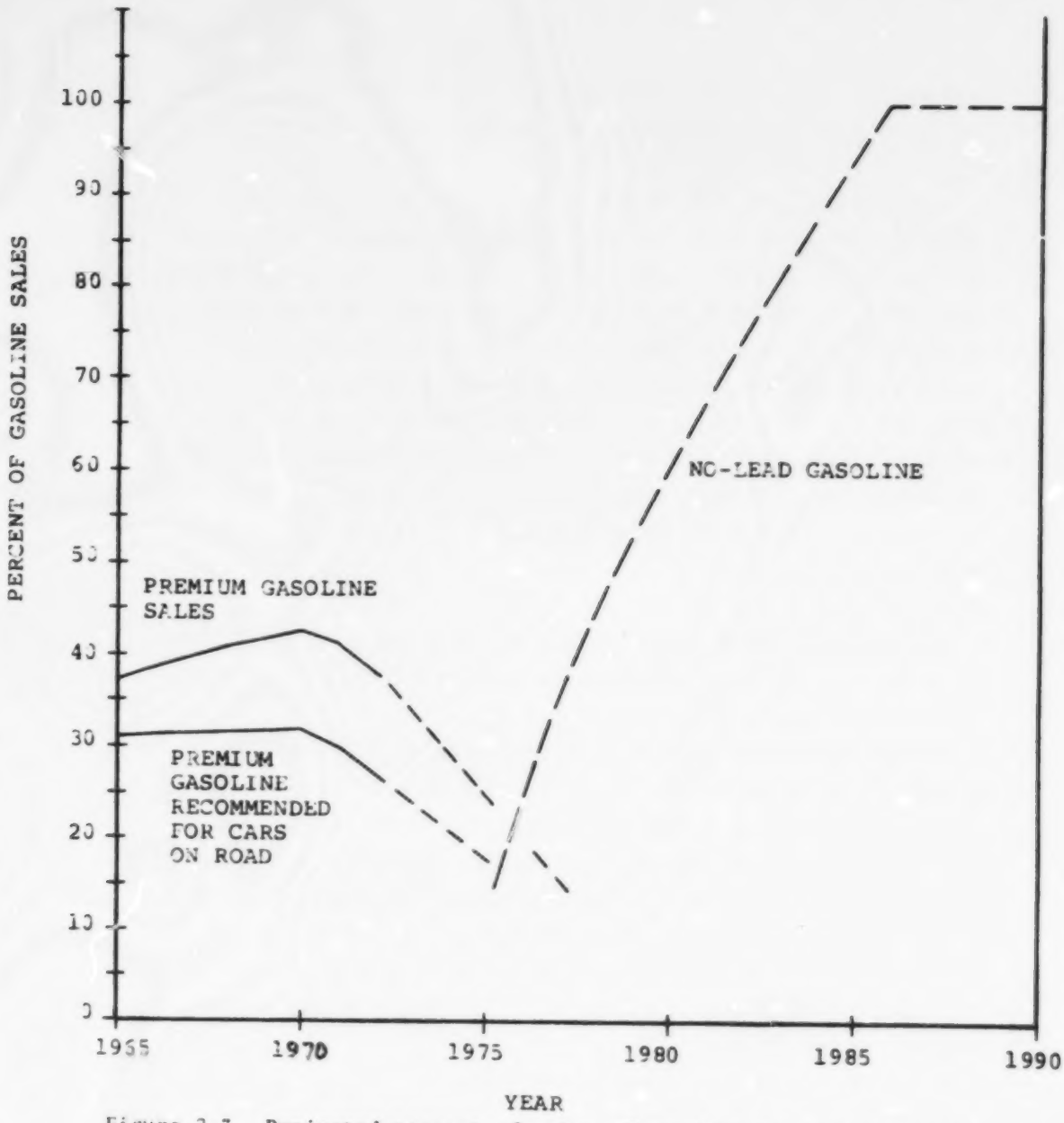

Figure 2-3. Projected percent of sales of premium and no-lead gasolines.

Table 2-5. POTENTIAL GASOLINE PRODUCTION IN CASE 1[1] WITH LEAD PHASE-DOWN

Year	1972	1975	1976	1977	1978	1979
Lead Content, g./gal						
Allowed by EPA	4.2[2]	1.7	1.4	1.0	0.8	0.5
Total Gasoline Pool		1.6	1.55	1.5	1.3	1.3
Premium Gasoline		1.8	2.6	3.0	-	-
Regular Gasoline		2.0	2.1	2.4	2.3	2.3
Potential Gasoline, vol%						
No-Lead, Low Sulfur		18	30	40	45	45
Premium (100 RON)	37	23	16	9	None	None
Regular (94 RON)	63	59	54	51	55	55
No-Lead Gasoline, vol%						
N-Butane		15	15	15	15	15
Alkylate		22	22	22	22	22
Reformate		63	63	63	63	63
Premium Gasoline, vol%						
					None	None
N-Butane		15	13	12		
Alkylate		22	15	12		
Reformate		63	44	35		
FCC Gasoline			28	41		
Regular Gasoline, vol%						
N-Butane		8	8	7	7	7
Light Virgin Gasoline		25	27	29	27	27
Light Coker Gasoline		2	2	2	2	2
FCC Gasoline		59	57	61	64	64
Alkylate		1	1	-	-	-
Reformate		5	5	1	-	-
Gasoline Octanes						
No-Lead, Research		94.7	94.7	94.7	94.7	94.7
Motor		87.9	87.9	87.9	87.9	87.9
Premium, Research	99.7	100.2	100.2	100.2		
Motor	92.2	94.8	93.3	92.6		
Regular, Research	94.0	94.2	94.2	94.2	94.2	94.2
Motor	86.4	86.3	87.0	86.3	86.2	86.2
Comment - See Note			3.	4.	5.	6.

Notes on Table 2-5:

(1) Potential gasoline blends are based on the gasoline yields and properties from "A" Typical U.S. Refinery (Case 1). The no-lead, low-sulfur gasoline would be blended from normal butane, alkylate, and reformate.

(2) Legal limit was 4.2 grams lead content per gallon prior to EPA regulations.

(3) Predicated sales demand of premium gasoline and no-lead, low-sulfur gasoline precludes meeting the EPA limit on lead content in 1976.

(4) Predicated sales demand of no-lead, low-sulfur gasoline reduces the production of premium gasoline below predicted sales demand. Lead content in total gasoline pool exceeds EPA regulation in 1977.

(5) In 1978 and 1979, the octanes of the gasoline components limits the production of no-lead, low-sulfur gasoline below predicted sales demand. The production of no-lead, low-sulfur gasoline precludes the production of premium gasoline. The lead content in the total gasoline pool exceeds the EPA regulation in 1978 and 1979.

CHAPTER 5

DESULFURIZATION OF GASOLINE

CASE 2: "A" REFINERY WITH HYDRODESULFURIZATION OF CATALYTIC CRACKER FEED AND LIGHT GASOLINES

In order to calculate the costs of producing low-sulfur gasolines, hydrodesulfurization of the gas oil feedstock to catalytic cracking and hydrodesulfurization of the light virgin and light coker gasolines were considered.

In Case 1, the sulfur content in the light virgin gasoline is 0.01 wt.%. However, hydrodesulfurization of light virgin gasoline should be included for the "typical" refinery for cost purposes because some of these gasolines, as shown in Table IV, have high sulfur contents.

In Case 2, the refinery process units would be same as in Case 1 of "A" Typical U.S. Refinery with the following additions:

- Gas Oil Hydrodesulfurization
- Light Gasoline Hydrodesulfurization
- New Capacity for Amine Treating and Sulfur Recovery

Figure 2-4 is a block flow diagram of Case 2 showing the yields and properties of the intermediate and final product streams. The yields and product properties are listed in Table 2-2 together with the average U.S. production.

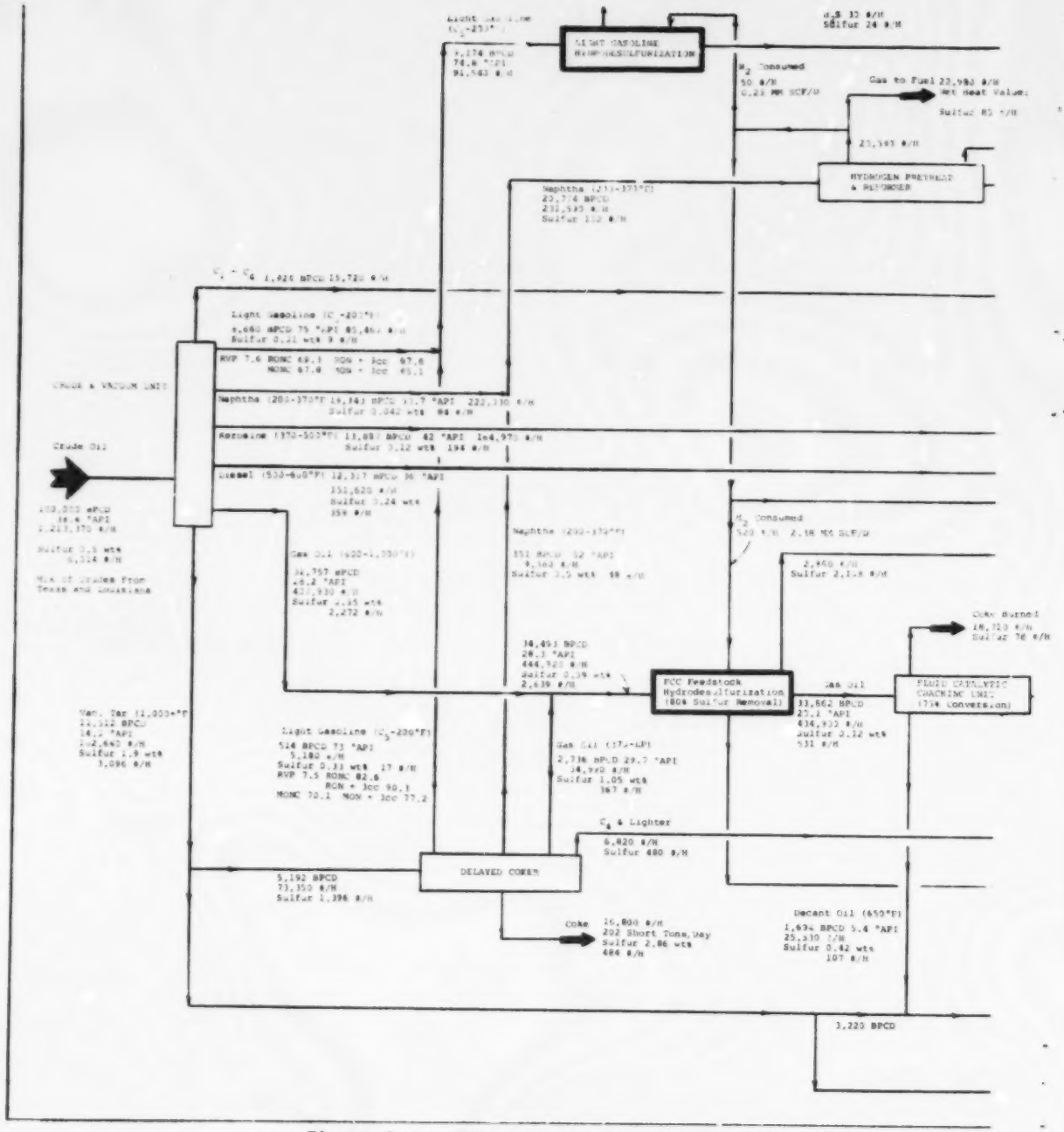

Figure 2-4. "A" typical U.S. refinery with hydrodesulfuriza-

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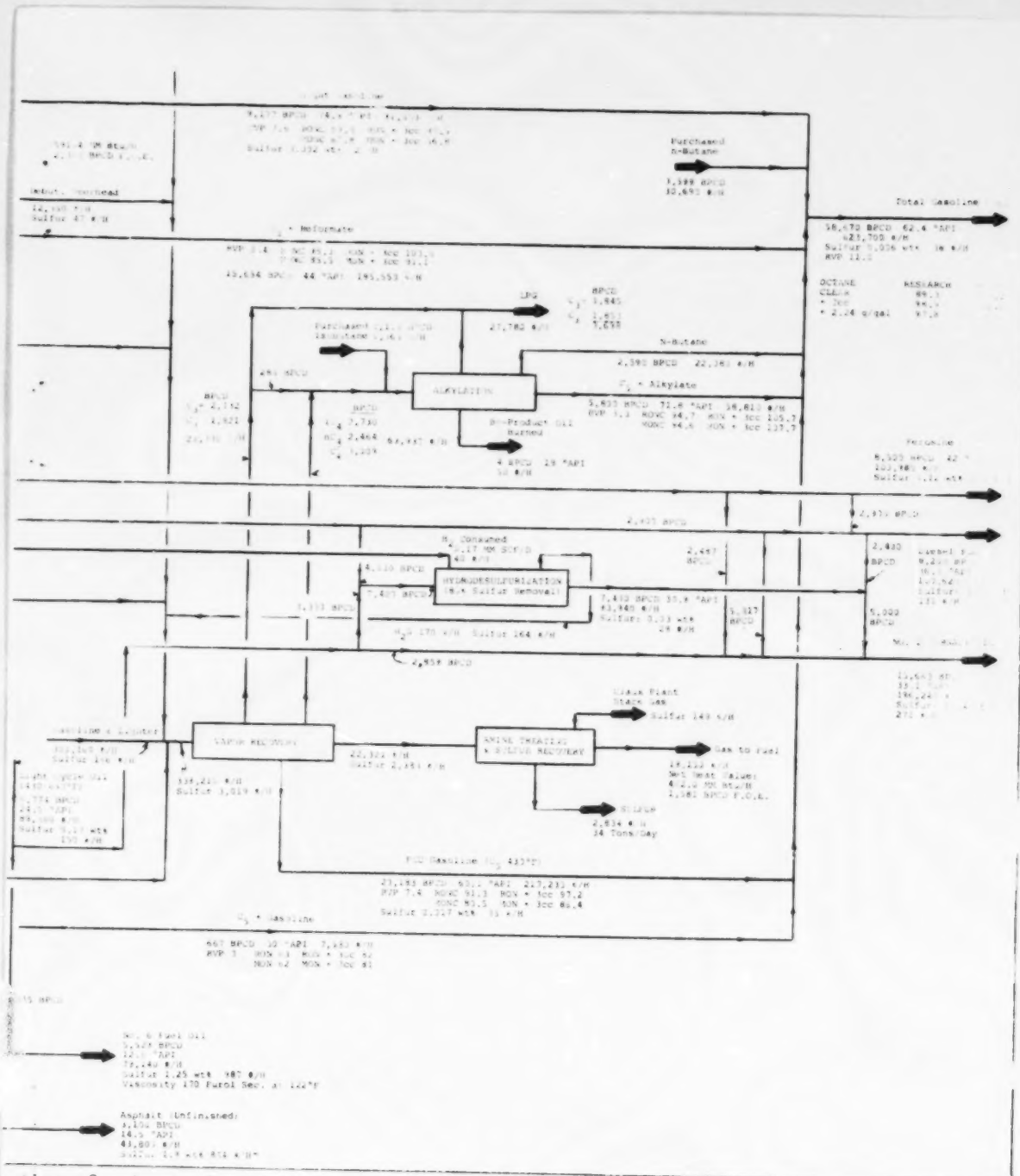

tion of cal. cracker feed and light gasolines.

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For desulfurization of the gas oil, the calculations are based on 80 percent sulfur removal with a hydrogen consumption of 42 standard cubic feet per pound sulfur removed (3.5 mols hydrogen consumed per mol sulfur removed). Above 85 percent sulfur removal, the hydrogen consumption increases due to saturation of polyaromatics and hydrocracking.

In Case 2, the hydrogen produced in the reformer would be more than adequate to supply the refinery needs. The sulfur content would be 0.008 weight percent in the total gasolines.

Economics for producing low-sulfur gasoline in Case 2 are summarized in Table 2-6 and estimated investments for the desulfurization facilities are shown in Table 2-7. The economic basis is presented in the Appendix. The investment for the desulfurization facilities is assumed to pay out in five years (20 percent rate of return.)

The total added costs to produce low-sulfur gasolines (above Case 1) depends upon refinery size as follows:

Refinery Capacity, BPCD	Added Costs to Produce Low-Sulfur Gasoline, Cents Per Gallon
16,000	1.59
44,000	1.01
100,000	0.67

Table 2-8 shows a comparison of yields in Case 1 and Case 2. Table 2-9 shows the estimated

Table 2-6. COSTS FOR GASOLINE DESULFURIZATION - CASE 2*

Refinery Capacity, BPCD	100,000	44,000	16,000
Investment for Desulfurization Facilities, Million Dollars	11.1	7.5	4.4
Years to Payout	5.0	5.0	5.0
Million Dollars Per Year:			
Cash flow	2.22	1.50	0.88
Depreciation	0.74	0.50	0.29
Net Profit	1.48	1.00	0.59
Income Tax	1.48	1.00	0.59
Gross Margin	2.96	2.00	1.18
Operating Costs:			
Depreciation	0.74	0.50	0.29
Operating Manpower	0.32	0.32	0.22
Utilities	2.09	0.92	0.33
Catalyst Replacement	0.23	0.10	0.04
Interest	0.56	0.38	0.22
Maintenance	0.36	0.26	0.16
Local Taxes and Insurance	0.15	0.11	0.06
Credit for Added Products	-1.00	-0.44	-0.16
Credit for Lower Butane Charges	-0.34	-0.15	-0.05
Total Operating Costs	3.11	2.00	1.11
Total Added Costs for Low-Sulfur Gasolines:			
Million Dollars Per Year (Gross Margin + Operating Costs)	6.07	4.00	2.29
Cents Per Gallon Gasoline	0.67	1.01	1.59

*Compared to Case 1

Table 2-7. INVESTMENT FOR DESULFURIZATION FACILITIES

	100,000 BPCD		44,000 BPCD		16,000 BPCD	
	Unit Capacity	Invest.* MM$	Unit Capacity	Invest.* MM$	Unit Capacity	Inves MM$
Light Gasoline Hydrodesulfurizer	4,700 BPSD	2.8	4,300 BPSD	2.0	1,600	1.3
Hydrodesulfurizer for FCC Feedstock	35,000 BPSD	5.6	16,000 BPSD	3.6	6,000	2.1
Sulfur Recovery (Claus Plant)	15 Ton/Day	0.3	7 Ton/Day	0.2	None	-
Onsite Subtotal		8.7		5.8		3.4
Offsites		2.4		1.7		1.0
Total Investment		11.1		7.5		4.4

* Investment include paid-up royalty (if applicable) plus initial charge for catalyst.

Table 2-8. COMPARISON OF YIELDS - CASE 1 AND CASE 2

	BPCD		
	Case 1	Case 2	Difference (Case 2-Case 1)
Charges			
Crude Oil	100,000	100,000	-
Isobutane	863	1,103	240
N-Butane	3,964	3,599	-365
Total Charges	104,827	104,702	-125
Products			
Fuel Gas, F.O.E.	4,060	3,908	-152
LPG (Propane-Propylene)	3,391	3,698	307
Gasolines	58,306	58,670	364
Kerosine	8,500	8,500	-
Diesel Fuel	8,200	8,200	-
No. 2 Furnace Oil	16,023	15,663	-360
No. 6 Fuel Oil	5,324	5,529	205
Delayed Coke (5 Bbl = 1 Ton)	1,008	1,008	-
Asphalt	3,100	3,100	-
Sulfur	(20 tons/day)	(34 tons/day)	(14 tons/day)
Total Products (Excluding Sulfur)	107,912	108,276	364
Apparent Gain (Products Minus Charges)	3,085	3,574	489

Table 2-9. UTILITIES AND CATALYST REPLACEMENT - CASE 2*

Process Unit	Light Gasoline Hydro-Desulfurization	FCC Feed Hydro-Desulfurization	Sulfur Recovery	Total
Capacity	9,700 BPSD	36,000 BPSD	15 TPD	
Consumption of Utilities:				
Electricity, KW	240	1,800	30	2,070
Fuel, MM Btu/Hr	24	126	1	151
Cooling Water, GPM	400	1,260	3,940	5,600
Boiler Feedwater, lb/hr		1,100	4,000	5,100
Steam Consumed, lb/hr				
Steam Generated, lb/hr		1,100	3,800	4,900
Wash Water, GPM	10	40		50
Cost of Utilities, $/CD				5,720
Catalyst Replacement, $/CD	40	620		660
Fuel Equivalent of Utilities, BPCD (F.O.E.)				650

*Utilities and catalyst replacement are incremental above those in Case 1.

utilities and catalyst replacement cost in Case 2.

The apparent liquid gain in products over charges for Case 2 is 489 BPCD above Case 1. However, the utilities for the desulfurization facilities would require 650 BPCD of fuel equivalent. Thus, Case 2 would show a net loss of 161 BPCD in comparison to Case 1.

Investment to Produce Low-sulfur Gasolines in the United States - Case 2

Based on the process scheme shown in Case 2, a crude oil throughput at 15 million barrels per day in 1978, and investment for the new desulfurization facilities at January, 1974 costs, the total investment would add about 2.03 billion dollars to U.S. refinery facilities. This investment would be portioned depending upon refinery size as follows:

Range of Refinery Crude Capacity, BPSD	% of Crude Capacity	Investment, Million Dollars
0 to 25,000	7.5	310
25,000 to 75,000	20.4	520
75,000 and larger	72.1	1,200
	100.0	2,030

This investment applies to the typical U.S. refineries and could be higher depending upon future imports of high sulfur crude oils. Increased imports of high sulfur crude oils would require desulfurization at increased severities for streams presently being desulfurized and installation of desulfurization facilities for other refinery streams.

In this event hydrogen for the refinery needs may not be sufficiently available from the reformer and new hydrogen production facilities may be required.

Potential Gasoline Production in Case 2 with Lead Phase-Down

The potential production of no-lead, premium, and regular gasolines was calculated attempting to meet the EPA regulations on lead phase-down using the blending components produced in Case 2. All the gasolines would be low-sulfur. These results (Table 2-10) indicate that the projected percent of gasoline sales and EPA regulations on lead phase-down can be met through 1978. In 1979, octane upgrading would be required to meet the EPA regulations on lead content.

Table 2-10. POTENTIAL GASOLINE PRODUCTION IN CASE 2[1] WITH LEAD PHASE-DOWN

Year	1976	1977	1978	1979[2]
Lead Content, g/gal				
Allowed by EPA	1.4	1.0	0.8	0.5
Total Gasoline Pool	1.1	1.0	0.8	0.8
Premium Gasoline	1.8	1.8	1.8	1.8
Regular Gasoline	1.5	1.7	1.4	1.9
Potential Gasoline, vol%				
No-Lead (92 RON)	30	40	49	57
Premium (100 RON)	18	14	9	5
Regular (94 RON)	52	46	42	38
No-Lead Gasoline, vol%				
N-Butane	11	11	11	11
Alkylate	11	11	11	11
Reformate	33	33	33	33
FCC Gasoline	40	40	40	40
Light Gasoline	5	5	5	5
Premium Gasoline, vol%				
N-Butane	12	12	12	12
Alkylate	36	36	36	36
Reformate	19	19	19	19
FCC Gasoline	33	33	33	33
Light Gasoline	--	--	--	--
Regular Gasoline, vol%				
N-Butane	10	10	10	10
Alkylate	--	1	3	4
Reformate	29	27	25	23
FCC Gasoline	32	30	28	26
Light Gasoline	27	30	31	34
HDS Gasoline	2	2	3	3
Gasoline Octanes				
No-Lead, Research	92.2	92.2	92.2	92.2
Motor	84.3	84.3	84.3	84.3
Premium, Research	100.2	100.2	100.2	100.2
Motor	95.6	95.6	96.5	96.5
Regular, Research	94.2	94.2	94.2	94.2
Motor	87.2	87.5	87.8	88.3

(1) Potential gasoline blends are based on the gasoline yields and properties from Case 2, "A" Typical U.S. Refinery with Hydrodesulfurization of Cat Cracker Feed, Light Virgin Gasoline and Light Coker Gasoline".

(2) In 1979, lead content of total gasoline pool would exceed EPA regulation.

CASE 3

"A" REFINERY WITH HYDRODESULFURIZATION OF CATALYTICALLY CRACKED AND LIGHT GASOLINES (CASE 3)

Case 3 considers the cost to produce low-sulfur gasolines by hydrodesulfurization of the catalytically cracked gasoline rather than the feedstock to the catalytic cracker.

The refinery process units in Case 3 would be the same as in Case 1 with the following additions:

- FCC Gasoline Hydrodesulfurization
- Light Gasoline Hydrodesulfurization

Figure 2-5 is a block flow diagram of Case 3 showing the yields and properties of the intermediate and final product streams. The yields and product properties are compared with those for the U.S. average and Cases 1 and 2 in Table 2-2.

Sulfur removal from the FCC gasoline of about 80 percent was selected since this yields about the same sulfur content in the total gasolines as in Case 2. At this desulfurization severity, 45 percent of the FCC gasoline would be hydrogenated, which would result in decreased research octane. The octane debit and other results are summarized as follows:

- Table 2-11 - Octane Debit
- Table 2-12 - Economics of Producing Low-Sulfur Gasoline

- Table 2-13 - Investment for Desulfurization Facilities
- Table 2-14 - Comparison of Yields, Case 1 versus and Case 3
- Table 2-15 - Utilities and Catalyst Replacement Requirements

The apparent gain (difference between products and charges, Table 2-14 for Case 3 would be 6 BPCD above the apparent gain for Case 1. However, the utilities for the desulfurization facilities would require 501 BPCD of equivalent fuel oil (Table XV). Thus Case 3 would result in a net loss of 495 BPCD compared to Case 1.

Economics as shown in Table 2-12 indicate that the total added costs (above Case 1) would be 0.82 cents per gallon to produce low sulfur gasolines. These costs include the penalty of 0.30 cents per gallon of gasoline debited to the lower octanes which result from partial hydrogenation of olefins in the FCC gasoline.

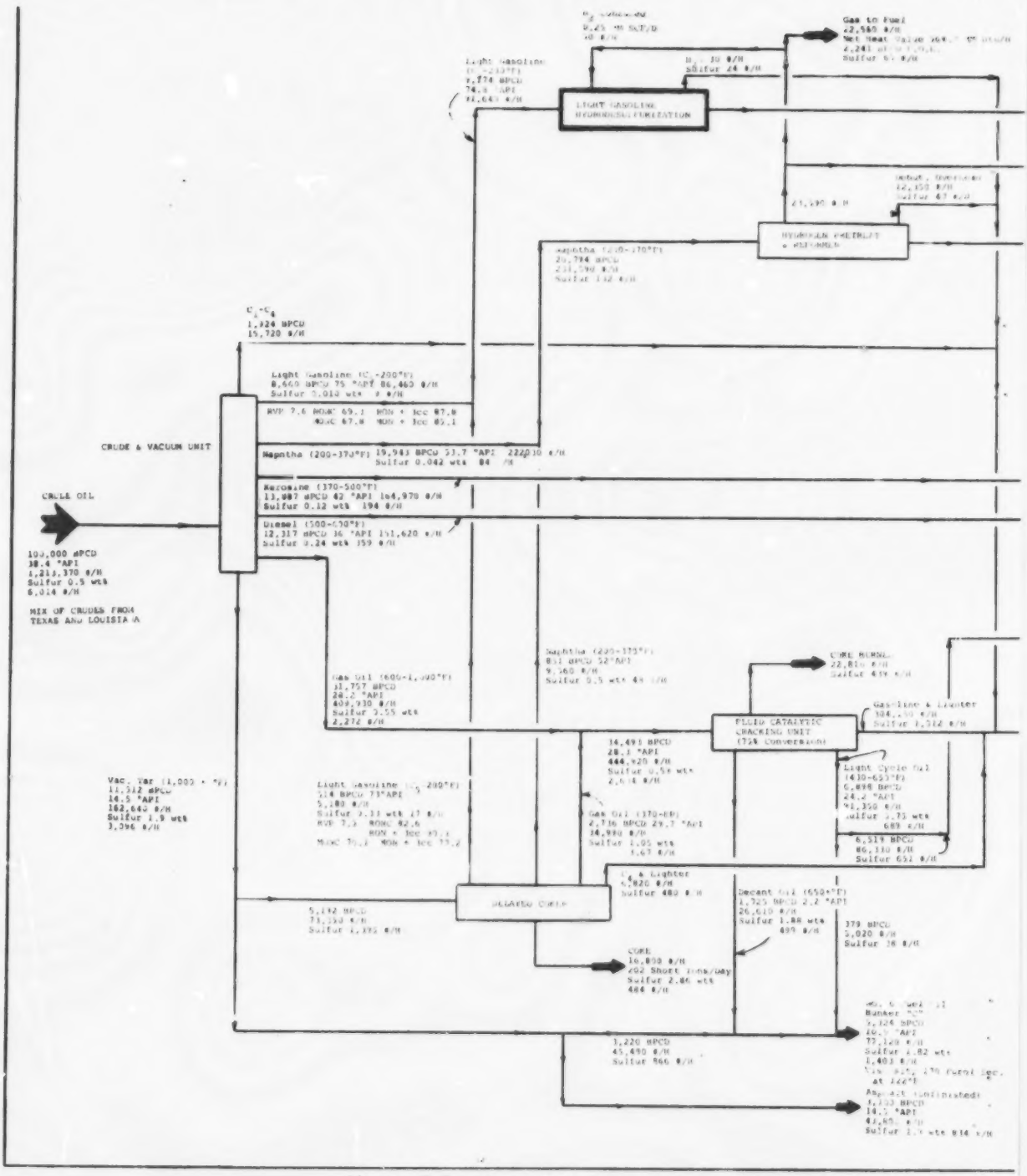

Figure 2-5. A typical U.S. refinery with hydrodesulfurization

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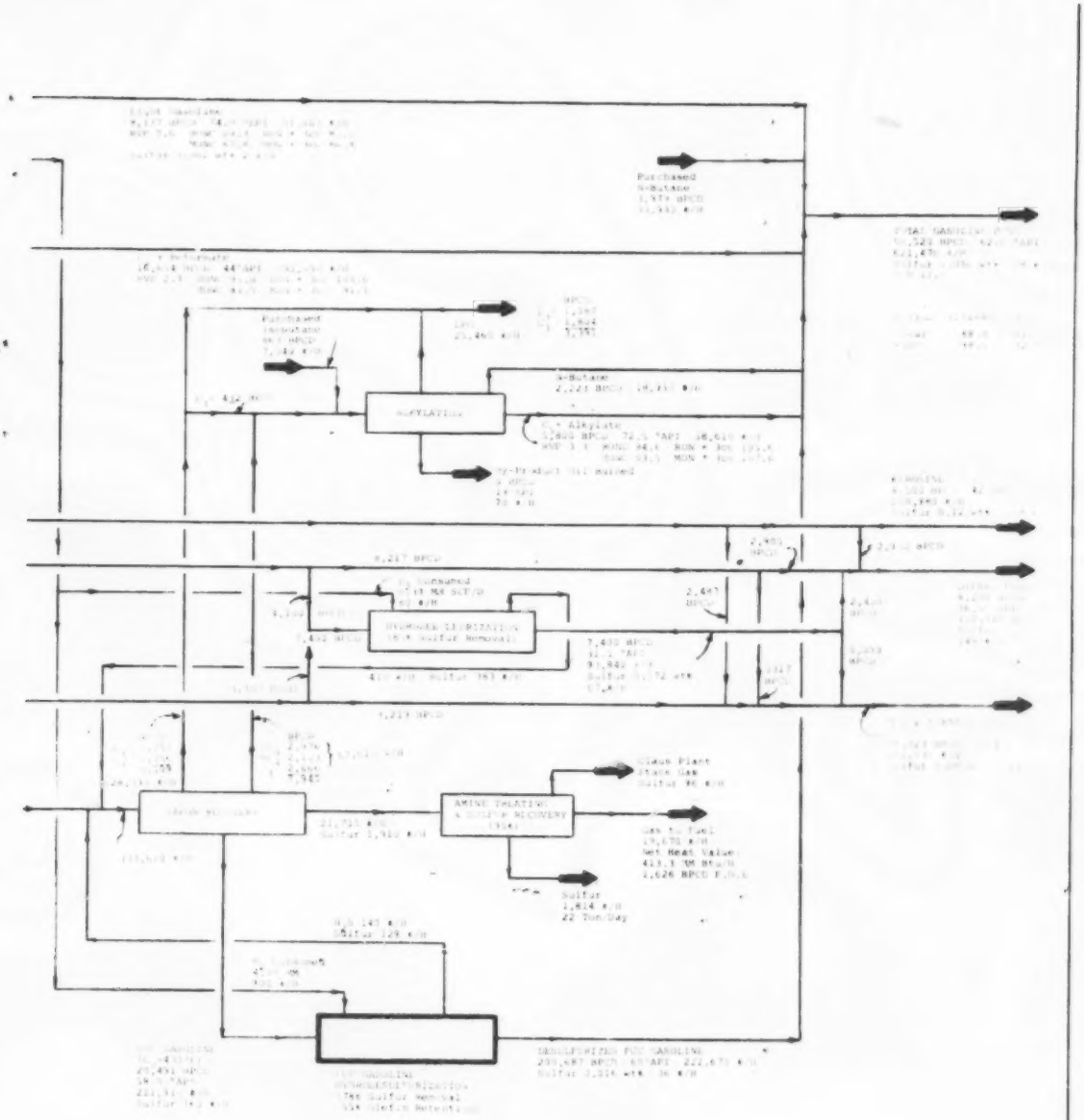

of cat cracked and light gasolines.

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Table 2-11. OCTANE DEBIT FOR CASE 3*

	Octane at 0.5 g/gal
Case 1	
Research	93.1
Motor	85.9
$\frac{\text{Research + Motor}}{2}$	89.5
Case 3	
Research	92.2
Motor	85.9
$\frac{\text{Research + Motor}}{2}$	89.1

Research Octane Penalty = 93.1 - 92.2 = 0.9 Octane

$$\text{Octane Debit} = \frac{0.9 \text{ Octane}}{} \Big/ \frac{\$0.02}{6 \text{ Octane,Gal}} \Big/ \frac{58{,}520 \text{ Bbls}}{\text{Day}} \Big/ \frac{42 \text{ Gal}}{\text{Bbl}} \Big/ \frac{365 \text{ Days}}{\text{Year}}$$

= $2.69 million/year

or 0.30 cents per gallon of gasoline.

*Compared to Case 1

Table 2-12. COST FOR GASOLINE DESULFURIZATION - CASE 3*

Refinery Capacity	100,000 BPCD
Investment for Desulfurization Facilities	$8.3 million
Years to Payout	5
Million Dollars Per Year:	
Cash Flow	1.66
Depreciation	0.55
Net Profit	1.11
Income Tax	1.11
Gross Margin	2.22
Operating Costs:	
Depreciation	0.55
Operating Manpower	0.22
Utilities	0.91
Catalyst Replacement	0.04
Interest	0.42
Maintenance	0.29
Local Taxes and Insurance	0.01
Credit for Added Products	-0.06
Cost for Added Butane	0.04
Debit for Lower Octane	2.69
Total Operating Costs	5.11
Total Added Cost for Low-Sulfur Gasolines (Gross Margin + Operating Costs)	7.33
Cents Per Gallon Gasoline	0.82

*Compared to Case 1

Table 2-13. INVESTMENT FOR DESULFURIZATION FACILITIES - CASE 3

	Capacity	Investment * Million Dollars
Refinery	100,000 BPCD	-----
Light Gasoline Hydrodesulfurizer Unit	9,700 BPSD	2.8
FCC Gasoline Hydrodesulfurizer Unit	21,600 BPSD	3.6
Onsite Subtotal		6.4
Offsite		1.9
Total Investment		8.3

Table 2-14. COMPARISON OF YIELDS - CASE 1 AND CASE 3

	BPCD		
Charges	Case 1	Case 3	Difference (Case 3-Case 1)
Crude Oil	100,000	100,000	----
Isobutane	863	863	----
N-Butane	3,964	3,979	15
Total Charges	104,827	104,842	15
Products			
Fuel Gas, F.O.E.	4,060	3,867	-193
LPG (Propane-Propylene)	3,391	3,391	----
Gasolines	58,306	58,520	214
Kerosine	8,500	8,500	----
Diesel Fuel	8,200	8,200	----
No. 2 Furnace Oil	16,023	16,023	----
No. 6 Fuel Oil	5,324	5,324	----
Delayed Coke (5 Bbl = 1 Ton)	1,008	1,008	----
Asphalt	3,100	3,100	----
Sulfur	(20 ton/day)	(22 ton/day)	(2 ton/day)
Total Products (Excluding Sulfur)	107,912	107,933	21
Apparent Gain (Products Minus Charges)	3,085	3,091	6

Table 2-15. UTILITIES AND CATALYST REPLACEMENT - CASE 3*

Process Unit	Light Gasoline Hydro-Desulfurization	Light Gasoline Hydro-Desulfurization	Total
Capacity	9,700 BPSD	21,600 BPSD	
Consumption of Utilities:			
Electricity, KW	240	1,070	1,310
Fuel, MM Btu/H	24	90	114
Cooling Water, GPM	400	1,430	1,830
Wash Water, GPM	10	30	40
Cost of Utilities, $/CD			2,490
Catalyst Replacement, $CD	40	70	110
Fuel Equivalent of Utilities, BPCD (F.O.E.)			501

*Utilities and catalyst replacement are incremental above those in Case 1.

SULFUR DISTRIBUTION

The sulfur contained in the crude oil to the refinery is distributed in the products, recovered as elemental sulfur, and emitted as SO_2 to atmosphere as shown in Table 2-16 for all three cases studied.

Sulfur contained in the gasoline is only a small fraction of the sulfur in the crude oil. Sulfur in the products used as fuels eventually will be emitted as sulfur oxides to the atmosphere as products of combustion unless stack gas scrubbing or other types of controls are used. The sulfur in delayed coke may be emitted as sulfur oxides to the atmosphere or be combined in metallurgical slag, depending upon the use of the delayed coke.

From the values tabulated in Table 2-16, it is seen that hydrodesulfurization of the gas oil feedstock to catalytic cracking (Case 2) results in:

- gasoline with the same sulfur content as Case 3 but lower than Case 1
- diesel fuel, No. 2 furnace oil and Banker "C" with lower sulfur than either Case 1 or 3
- increased recovery of elemental sulfur

Table 2-16. SULFUR DISTRIBUTION

Sulfur Content, Lb/hr	Case 1	Case 2	Case 3
Crude Oil	6,014	6,014	6,014
Products:			
Gasoline	191	38	38
Kerosine	119	119	119
Diesel Fuel	148	135	148
No. 2 Furnace Oil	554	271	554
Bunker C	1,403	987	1,403
Asphalt	834	834	834
Delayed Coke	484	484	484
Recovered as Elemental Sulfur	1,669	2,834	1,814
Emitted as SO_2 to Atmosphere	612	312	620
Total	6,014	6,014	6,014
Sulfur Distribution, %*			
Gasoline	3.2	0.6	0.6
Kerosine	2.0	2.0	2.0
Diesel Fuel	2.5	2.2	2.5
No.2 Furnace Oil	9.2	4.5	9.2
Bunker C	23.3	16.4	23.3
Asphalt	13.9	13.9	13.9
Delayed Coke	8.0	8.0	8.0
Recovered as Elemental Sulfur	27.7	47.2	30.2
Emitted as SO_2 to Atmosphere	10.2	5.2	10.3
Total	100.0	100.0	100.0

*As percent of sulfur in crude oil

APPENDIX A

GENERAL SITUATIONS OF REFINERIES IN THE UNITED STATES

No two crude oils or two refineries are the same. Furthermore, no two refineries will produce and have the same product demand. Depending upon the crude properties and refinery process capabilities, different refineries are geared to the following categories or combinations thereof:

- Production of gasolines, mid-distillates and residual oil
- Petrochemical production
- Lubricant production
- Asphalt production

United States refineries produce petroleum products in relation to the market demands for quantities and properties. Each refinery bases its operations on market demands and availability of crudes within the limitations of its refinery process units and the flexibility of operating conditions.

In crude topping and vacuum operations, crude oils can be distilled into fractions with true boiling cut points approximately as follows:

- Butanes and lighter components to gas recovery
- Pentanes to 200°F light gasoline for blending to gasoline or isomerization of the pentanes and hexanes to upgrade the octane number
- 200°F - 370°F naphtha for reformer feedstock to upgrade the octane number or produce aromatics

- 600°F - 1,000°F gas oil feedstock to catalytic cracking, thermal cracking or hydrocracking
- Heavier than 1,000°F residuum for blending No. 6 fuel oil or to asphalt or produced as feedstock for visbreaking, delayed coking, fluid coking or solvent deasphalting

Tyipcal ASTM distillations of refined products to sales are shown in Figure A-1. Gasolines distill in the range of 80°F to 400°F, kerosine and jet fuel (kerosine-type) distill in the range of 340°F to 530°F and diesel fuel and No. 2 fuel oil distill in the range of 350°F to 650°F. The term "mid-distillates" refers to the distillates boiling between gasoline and No. 6 fuel oil and comprises the kerosine, aviation jet fuel, diesel fuels and No. 2 heating oil. Kerosine, aviation jet fuel and No. 1-D diesel fuel are produced from the distillates boiling between 370°F and 500°F true boiling cut points. No. 2 heating oil and No. 2-D diesel fuel are blends of essentially 50 percent of the 370°F to 500°F fraction with 50 percent of the 500°F to 600°F fraction.

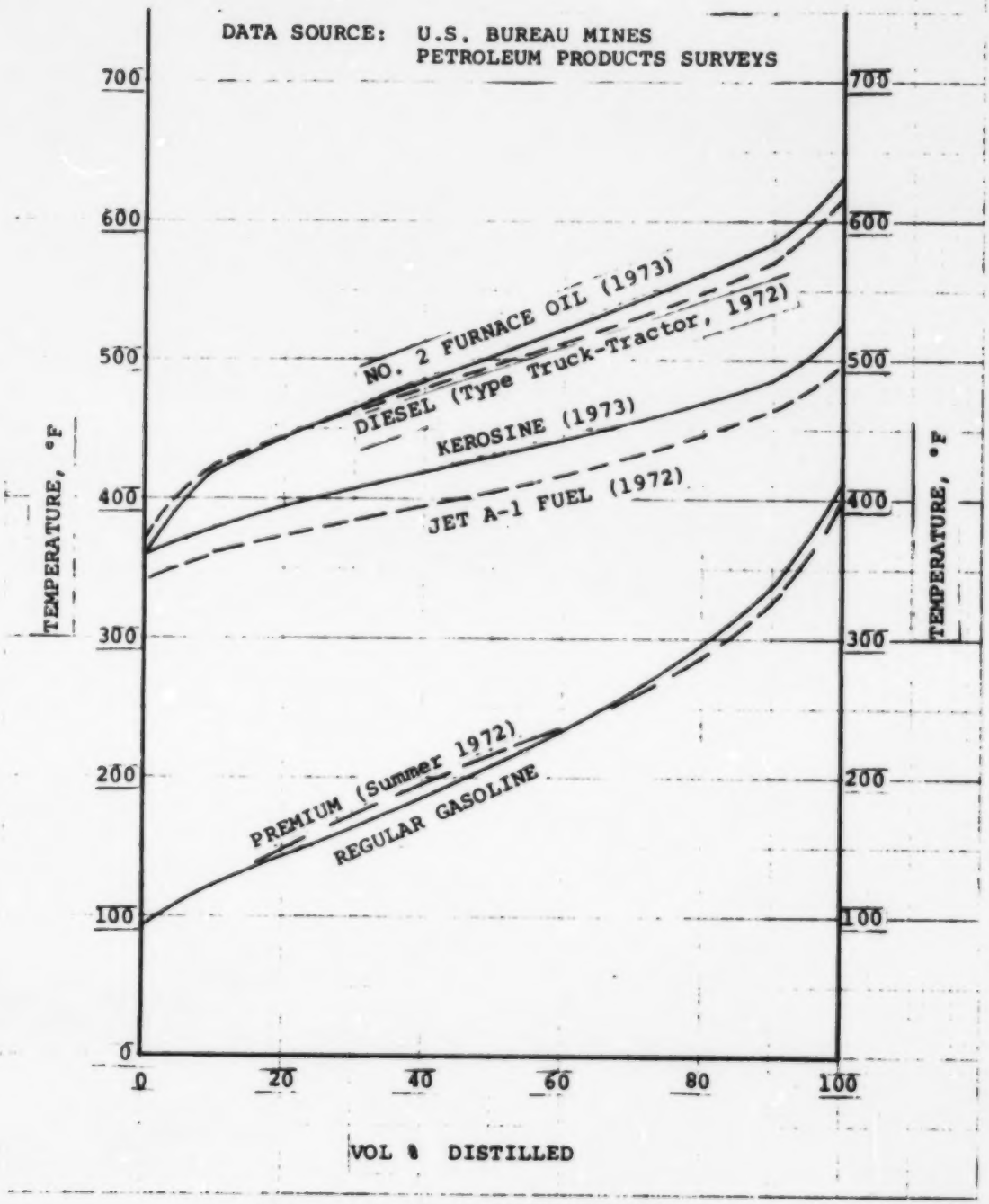

Figure A-1. Typical ASTM Distillations of Petroleum Products.

APPENDIX B
U.S. PRODUCTION OF PETROLEUM PRODUCTS

Table B-1 shows the range of crude capacities in U. S. refineries in 1973. Refineries larger than 25,000 BPSD have 92.5% of the U.S. crude capacity. The median quantity of crude is processed in U.S. refineries of about 100,000 BPSD crude capacity.

Table B-2 shows the charge capacity of U. S. refineries in 1973 by types of processing units.

Table B-3 shows the production U. S. refinery products in 1971. Table B-4 shows the U. S. demand for mid-distillates by use in 1973.

Table B-5 shows typical properties of the petroleum products sold in the United States in 1972 and 1973.

The 1972 properties of the total U.S. gasoline pool were estimated from U.S. Bureau of Mines surveys and Ethyl Corporation sales data as follows:

Research Octane	97.5
Motor Octane	90.0
Lead, g/gal.	2.24
Sulfur, wt%	0.031

The response of lead content in the total U.S. gasoline pool was estimated from the lead response of various premium and regular gasoline blends. Figure B-1 shows the research and motor octanes of the total U.S. gasoline pool in 1972 as a function of lead content.

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Table B-1. CRUDE CAPACITIES OF U.S. REFINERIES IN 1973

Range of Crude Capacities, BPSD	Number of Refineries	Crude Capacity, BPSD		% of U.S. Crude Capacity
		Total	Average	
0-10,000	76	340,000	4,500	2.4
10,000-25,000	43	702,000	16,000	5.1
25,000-75,000	64	2,826,000	44,000	20.4
75,000-125,000	31	3,033,000	98,000	21.9
125,000-200,000	15	2,298,000	153,000	16.5
200,000-300,000	8	2,145,000	268,000	15.4
Larger Than 300,000	7	2,546,000	364,000	18.3
Total	244	13,890,000		100.0
Refineries Larger Than 25,000 BPSD	125	12,848,000	103,000	92.5

Table B-2. CAPACITY OF PROCESS UNITS IN UNITED STATES IN 1973

Process Unit	Charge Capacity, BPSD	Vol. % of Crude Capacity	
Crude Distillation	13,890,000	100.0	
Vacuum Distillation	5,150,700	36.8	
Delayed Cokers	776,900	5.6	6.4
Fluid Cokers	118,200	0.8	
Visbreakers	237,300	1.7	
Hydrogen Desulfurization:			
Naphtha	2,798,800	20.0	
Mid-Distillates	1,109,700	7.9	
FCC Feedstock	279,800	2.0	
Heavy Gas Oil	184,000	1.3	
Reduced Crude	19,500	0.14	
Cat Crackers (Fresh Feed)	4,512,600	32.3	
Hydrocrackers	865,100	6.2	
Cat Reformers	3,278,100	23.4	
Alkylation (Sulfuric Acid)	531,300	3.8	5.8
Alkylation (Hydrofluoric Acid)	280,600	2.0	
Aromatics (Benzene-Toluene-Xylenes)	188,500	1.3	
Isomerization			
Butane	49,600	0.35	
Pentane	34,100	0.24	
Pentane-Hexane	37,500	0.27	
Lubes	221,900	1.6	
Asphalt	644,300	4.6	
Coke	(42,700 ton/day)	(0.00305 tons coke per barrel crude)	

Table B-3. U. S. REFINERY PRODUCTS IN 1971

Refinery Input	Million Barrels		Input, %*	
Crude Runs to Still	4,088		100.0	
Natural Gas Liquids	359		8.8	
	4,447		108.8	
Refinery Production	**Million Barrels**		**Yield, %***	
Motor Gasoline	2,179		53.3	
Aviation Gasoline	18		0.4	
Naphtha in Naphtha-Type Jet Fuel	43		1.1	
Special Naphthas	28		0.7	
Petrochemical Feedstocks	111		2.7	
Total Gasoline-Naphtha		2,379		58.2
Ethane-Ethylene	9		0.2	
Liquefied Petroleum Gas (LPG)	32		0.8	
Propane-Propylene	12		0.3	
C_3-C_4 Mix	3		0.1	
Total Light Components		56		1.4
Kerosine	87		2.1	
Kerosine-Type Jet Fuel	219		5.4	
Kerosine in Nahptha-Type Jet Fuel	42		1.0	
Total Kerosine		348		8.5
Distillate Fuel Oil		911		22.3
Residual Fuel Oil	275		6.7	
Asphalt (5.5 bbl = 1 short ton)	157		3.8	
Road Oil	9		0.2	
Total Residual Oil		441		10.8
Lubricants	65		1.6	
Wax (1 bbl = 280 lb)	7		0.2	
		72		1.8
Coke (5 bbl = 1 short ton)		62		1.5
Miscellaneous Products		14		0.3
Still Gas to Fuel	157		3.8	
C_3 to Fuel	5		0.1	
C_4 to Fuel	14		0.3	
LPG to Fuel	3		0.1	
		179		4.3
Accounted Yield		4,462		109.1
Difference (Accounted Minus Input)		15		0.3

*Volume percent on crude input

Table B-4. U.S. DEMAND FOR MID-DISTILLATES BY USE IN 1973

	Million Barrels		%	
Kerosine	80		6.1	
Kerosine-type Jet Fuel	233		17.6	
Kerosine Content of Naphtha-type Jet Fuel	38		2.9	
No. 1 Range Oil	15		1.1	
		366		27.7
Diesel Fuel Used on Highways	164		12.4	
Industrial Uses	50		3.8	
Oil Company Fuel	14		1.1	
Railroads	86		6.5	
Vessel Bunkering	21		1.6	
Military Uses	17		1.3	
		352		26.7
Heating Oil	509		38.5	
Gas and Electric Company Public Utility Power Plants	35		2.6	
		544		41.1
Miscellaneous and Unaccounted		60		4.5
Total Mid-distillates		1,322		100.0

Table B-5. TYPICAL PROPERTIES OF PETROLEUM PRODUCTS

	REGULAR GASOLINE	PREMIUM GASOLINE	REGULAR GASOLINE	PREMIUM GASOLINE	TOTAL GASOLINE POOL	KEROSINE	JET A-1 FUEL	DIESEL FUEL (TRUCKS-TRACTORS)	NO. 2 FURNACE OIL	NO. 6
U.S. Bureau Mines Survey	Summer 1972	Summer 1972	Winter 1972-73	Winter 1972-73	Average 1972	1973	1972	1972	1973	1973
Gravity, °API	60.5	60.7	62.5	63.0	61.7	42.3	42.4	36.5	35.1	11.0
Distillation, ASTM, °F										
IBP	92	91	84	84		341		375	367	
10%	122	123	108	109		378	362	427	425	
30	163	172	150	158						
50	208	217	200	209		428	405	495	504	
70	262	257	257	251						
90%	339	324	334	352		485	464	573	589	
EP	411	401	405	397		525		618	635	
Sulfur, wt %	0.042	0.026	0.038	0.023		0.067	0.065	0.21	0.22	1.60
Aniline Point, °F						146	140	147	144	
Cetane Number								48.6		
Viscosity, CS at 100°F						1.66		2.71	2.71	
Viscosity, Furol at 122°F										170
Carbon Residue, wt %										9.3
Lead, g/gal.	2.04	2.52	1.80	2.34						
Octane Number:										
Research	94.1	99.8	93.9	99.6						
Motor	86.4	92.2	86.4	92.2						
(Research + Motor)/2	90.3	96.0	90.2	95.9						
Reid Vapor Pressure	9.2	9.3	12.2	12.1						
Total Gasoline:										
Sales, %	38	62	37	63						
Sulfur, wt %	0.032		0.029		0.031					
Research Octane	97.6		97.5		97.5					
Motor Octane	90.0		90.1		90.0					
(Research + Motor)/2	93.8		93.8		93.8					
Lead, g/gal.	2.34		2.14		2.24					
Reid Vapor Pressure					10.7					

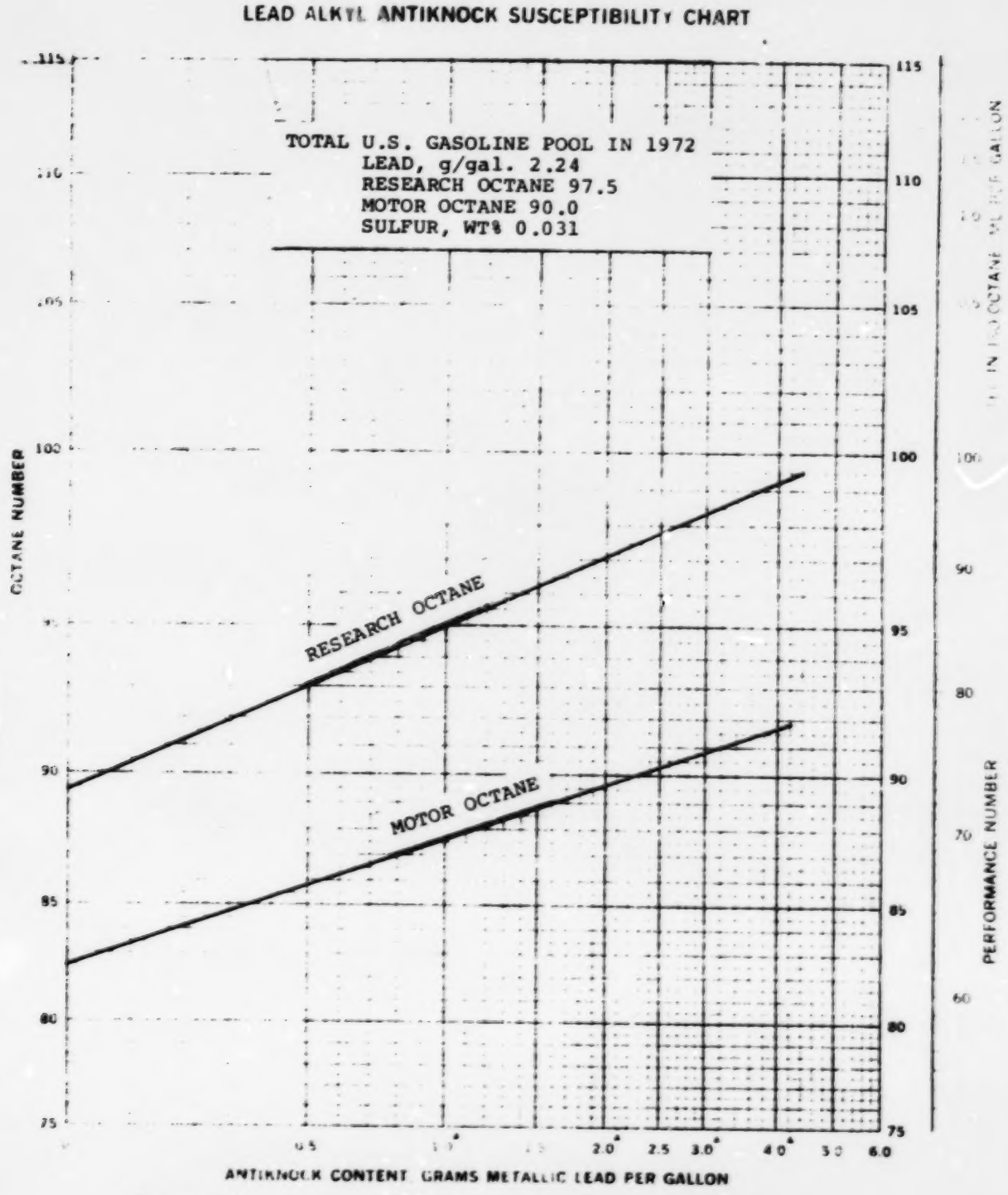

Figure B-1. Octane of Total U. S. Gasoline Pool in 1972.

APPENDIX C

COSTS

1. All costs and capital are based on January, 1974 levels.
2. Capital related charges

   Straight-line depreciation for 15 year life

   Interest at 10 percent per year. This is equivalent to 5 percent per year over the average payout period.

   Maintenance: onsite, 4 percent; offsite, 2 percent

   Local taxes and insurance: 1.5 percent

   Payout on investment: 5 years after taxes
3. U.S. income plus state corporation taxes at 50 percent of gross profit.
4. Incremental utility costs for new facilities

   Fuel: $1.40 per million Btu net heat value. This is equivalent to $7.50 per barrel of 38°API crude oil.

   Electricity:

	$ Per KWH
Fuel cost	0.014
Other charges	0.006
	0.020

   Steam:

   $1.90 per 1,000 pounds corresponding to the fuel cost of $1.40 per million Btu.

   Cooling Water:

   $0.20 per 1,000 gallons circulation

   Treated boiler feedwater

   $0.05 per 1,000 pounds
5. Operating manpower costs

   Average costs for stillman and operators at $6.00 per hour plus 30 percent fringe benefits. Sixty percent overhead on operating manpower is added to allow for supervision, laboratory, technical service

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and instrument services.

Manpower Cost Per Shift Position	$/HR	%	$/YR
Rate	6.00		52,600
Fringe Benefits		30	15,800
Overhead		60	41,000
TOTAL			109,400

6. Product prices

   Incremental product yields were priced at the same price as crude oil ($7.50 per barrel).

7. Royalties

   Gas oil hydrodesulfurization:

   Paid-up royalty $10.00 per BPCD feed rate

   Naphtha hydrodesulfurization:

   Royalty-free. Royalty costs would be included in catalyst costs or nominal know-how fee.

8. Hydrogen make-up

   Assumed to be available in the reformer make-gas for hydrodesulfurization units.

9. Gasoline octane

   Incremental gasoline octane priced at 2.0 cents per 6 octane difference between premium and regular gasolines at the 1972 lead level of 2.24 grams per gallon. This price is equivalent to 0.333 cents per gallon per research octane number.

APPENDIX D
OIL EQUIVALENT OF UTILITIES

1. Fuel

   Net heat value at 6.1 million Btu per barrel fuel oil equivalent. (F.O.E.)

2. Electricity

   Net heat to generate electricity is assumed to be 10,000 Btu per kilowatt-hour. This requires 0.04 BPCD F.O.E. per kilowatt-hour.

3. Steam

   Net heat to generate steam is assumed to be 1,370 Btu per pound of steam. This requires 5.4 BPCD F.O.E. per 1,000 pounds per hour of steam.

APPENDIX E
SOURCES OF INFORMATION

American Petroleum Institute

"Annual Statistical Review, U.S. Petroleum Industry Statistics, 1972"

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PART 3

PRODUCTION OF LOW-SULFUR GASOLINES IN CALIFORNIA REFINERIES

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CHAPTER 1

INTRODUCTION

This part of the report covers work which was performed under Contract 68-02-1308 for the Environmental Protection Agency (EPA), Office of Research and Monitoring, Task 10, Phase 3.

The purpose of this work is to determine the impact of producing low-sulfur gasolines on the refineries supplying California and the Los Angeles area. Refineries in the Los Angeles area account for 56% of the crude capacity in California. For this work, the basic refinery was considered to have process units with capacities based on percent of crude input to be the average of refineries within California charging a crude mix with the average composition of crudes now being processed in California. Desulfurization facilities were then added to this basic refinery, using two processing schemes, to produce low-sulfur gasolines.

Refineries in California process crude mixes averaging 53% domestic crudes and 47% foreign crudes. The California crude oils are heavy crudes with high sulfur content. As the results of the heavy high sulfur charge stocks and the market demands in California, these refineries have more residual oil processing, more hydrogen treating of products, and more hydrocracking of gas oils than the "typical" refineries in the United States.

In order to show the maximum costs for producing low-sulfur gasolines, it was assumed that new facilities would be necessary to provide the incremental hydrogen, remove hydrogen sulfide and recover sulfur.

Part 2 of this report (Phase 2) presented a similar study based on a "typical" U. S. refinery and crude oil mix. The Phase 3 work supplements the Phase 2 report.

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CHAPTER 2

SUMMARY

This study shows how a model of the average refineries in California can produce no-lead, low-sulfur gasoline and by installing new hydrodesulfurization facilities can produce low-sulfur gasolines to include the no-lead, premium, and regular gasolines.

Results of this study show that the existing large California refineries can produce no-lead, low-sulfur gasoline at the projected percent of gasolines sales through 1979, blended from normal butane, light hydrocrackate, reformate, and alkylate. Beyond 1976, the predicted demand of no-lead and premium gasolines could not be met with EPA limits on lead anti-knock in the total gasoline pool.

Total gasolines can be made low-sulfur by hydrodesulfurization of the gas oil feedstock to catalytic cracking and by hydrodesulfurization of the light virgin gasoline and light thermally cracked gasolines. Economics for this scheme (Case 2) show that the costs** for producing low-sulfur gasoline would add 1.1 cents per gallon to the costs of manufacturing the present gasolines in refineries of 100,000 barrels per calender day (bpcd) capacities.

An alternate case considers hydrodesulfurization of the catalytically cracked gasoline rather than the feedstock to the catalytic cracker. Economics indicate that this scheme (Case 3) to produce low-sulfur gasoline would add about 1.0 cent per gallon to the present cost** of manufacturing gasolines in refineries of 100,000 bpcd capacities.

In California, there are eleven refineries which are larger than 75,000 bpsd.* The crude capacities for these eleven refineries total 1,402,000 bpsd which is 78% of the total crude capacity of all refineries in California. If new facilities were installed to produce low sulfur gasolines in these eleven refineries by desulfurizing the light virgin gasoline, light thermal gasolines, and catalytic cracker feedstock (Case 2), an investment of about 250 million dollars would be required based on May, 1974 costs.

Based on the gasoline yields and properties in Case 2 for low-sulfur gasolines, the predicted sales ratios of no-lead, premium, and regular gasolines could be blended and meet the EPA regulations on lead phase-down for 1975 and 1976. Additional processing for octane up-grading would be required starting in 1977 to meet the EPA regulations on further lead phase-down.

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* bpsd - Barrels per stream day
bpcd - Barrels per calander day

**Costs include 5 years payout on investment (20% rate of return) after taxes.

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CHAPTER 3

PRODUCTION OF NO-LEAD, LOW-SULFUR GASOLINE IN PRESENT CALIFORNIA REFINERIES

CRUDE OILS RUN IN CALIFORNIA REFINERIES

At present, California refineries process about 53% domestic crudes and 47% imported crudes. Table 3-1 shows the origins of crudes processed in District 5 which includes California. The California crude oils are typically heavy and high sulfur crudes. The Middle East are also typically high sulfur crudes. Therefore, the average mixture of crudes processed in California refineries is heavier and has higher sulfur content than the crudes processed in the average U.S. refinery.

Table 3-2 lists the crude mix selected for this study. This crude mix would be 28°API, 1.27 wt% sulfur, and 4.1 wt% Conradson carbon.

When the Alyeska pipeline begins delivering North Slope crude oil in 1977, this crude will probably be processed by the West Coast refineries and reduce their imports of foreign crude oils.

Addition of Alaskan North Slope crude oil to the West Coast crude mix will not materially effect the crude mix as the North Slope crude is 26°API, 1.1 wt% sulfur, and 6.0 wt% Conradson carbon.

AVERAGE OF CALIFORNIA REFINERIES - CASE 1

As the results of processing heavy crude oils with high sulfur contents and sales demands, the California refineries have more residual oil processing, more hydrogen treating of products, and more hydrocracking of gas oils than the "typical" refineries in the United States.

Table 3-3 shows the capacities of processing units in California refineries.

The refinery process units selected for Case 1 for an "Average of California Refineries" were as follows:

- Crude and Vacuum Distillation
- Catalytic Reformer with Hydrogen Pretreat Section
- Fluid Catalytic Cracker with Vapor Recovery
- Catalytic Hydrocracker
- Jet Fuel Hydrotreater
- Diesel Hydrotreater
- Alkylation
- Delayed Coker
- Visbreaker
- Solvent Deasphalting
- Amine Treating and Sulfur Recovery

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Table 3-1. CRUDE OILS FOR DISTRICT 5

	THOUSAND BARRELS PER DAY	VOL% OF TOTAL
Domestic Crudes:		
California	910	42.2
Alaska	190	8.8
Four-corners Pipeline	30	1.4
Rail From Utah	15	0.7
	1,145	53.1
Foreign Crudes:		
Canada	250	11.6
Venezuela	20	0.9
Ecuador, Peru	70	3.2
Middle East	470	21.9
Indonesia	200	9.3
	1,010	46.9
Total Crude Oils	2,155	100.0

From: Oil & Gas Journal, March 18, 1974

Table 3-2. SELECTED CRUDE MIX

	THOUSAND BARRELS PER DAY	VOL% OF TOTAL
California:	910	
Midway-Sunset		13
Huntington Beach		7
Wilmington		25
Alaska	190	9
Canada	250	13
Middle East (Arabian)	470	23
Indonesia (Minas)	200	10
Total	2,020	100

Table 3-3. PROCESSING UNITS IN CALIFORNIA REFINERIES

PROCESS UNIT	FEED CAPACITY BPSD		FEED CAPACITY VOL% ON CRUDE CAPACITY	
	Los Angeles Area	Total California	Los Angeles Area	Total California
Crude Distillation	996,000	1,785,200	100.0	100.0
Vacuum	509,500	930,000	51.2	52.1
Catalytic Cracking	284,500	473,500	28.6	26.5
Catalytic Hydrocracking	134,200	312,100	13.5	17.5
Thermal Cracking Gas Oil	23,000	32,500	2.3	1.8
Catalytic Reforming	245,700	463,700	24.7	26.0
Hydrotreating:				
Naphtha	234,000	425,400	23.5	23.8
Mid-Distillate	149,000	202,800	15.0	11.4
Other	-	64,000	-	3.6
Delayed Coking	210,000	252,500	21.1	14.1
Fluid Coking	-	71,000	-	4.0
Visbreaking	86,000	95,600	8.7	5.4
Alkylation, HF	15,800	15,800	1.6	0.9
Sulfuric Acid	33,600	73,000	3.4	4.1
Aromatics, BTX	4,000	5,500	0.4	0.3
Isomerization, C_4	5,000	9,700	0.5	0.5
C_5 & C_6	13,000	13,000	1.3	0.7
Lubes	-	23,800	-	1.3
Asphalt	47,100	96,400	4.7	5.4
Solvent Deasphalting	-	45,000	-	2.5

Figure 3-1 shows the flow scheme for this "Average of California Refineries".

To calculate the refinery yields, the following conditions were assumed:

- Crude input to basic California refinery (Case 1) would be 100,000 bpcd crude oil.
- Catalytic cracker would operate at 75% conversion with yields corresponding to riser cracker with zeolite catalysts.
- Production of alkylate was set at 5.0 vol% on crude input by taking propylene to LPG.
- Reformer severity would produce 95 research octane clear.
- Unfinished asphalt would be produced from vacuum residuum and asphalt from solvent deasphalting.
- Production of lubricants and waxes were not considered as these account for only 0.9 vol% on crude input.
- Special naphthas and the benzene - toluene - xylenes aromatics were considered to be part of reformate and would be accounted in the total gasolines.

Capacities of the process units required to process the streams from the selected crude mix in Case 1 are compared in Table 3-4 with the average of California refineries based on percent of crude input.

Product yields and properties in Case 1 are compared in Table 3-5 with products produced in California refineries.

The comparisons in Table 3-4 and Table 3-5 show that refinery model and crude mix used in Case 1 may be considered an average of the California refineries.

For Case 1, the overall material balance is shown in Table 3-6 and the gasoline pool is shown in Table 3-7.

The volumetric blended octanes shown in Table 3-7 were corrected for sensitivities, olefin content and aromatic content. The corrected octanes are shown in Figure 3-2.

SALES OF PREMIUM AND NO-LEAD GASOLINES IN CALIFORNIA

During the period 1953 to 1972, the premium gasoline sales as percent of total gasoline sales in California has been 16 to 20% higher than the average for the United States.

Figure 3-3 shows a projected percent of sales of premium gasoline and no-lead gasoline in California. It was assumed that the premium gasoline would be 25% of sales in 1977. The sales requirements for premium gasoline will continue to decrease as the pre-1971 high

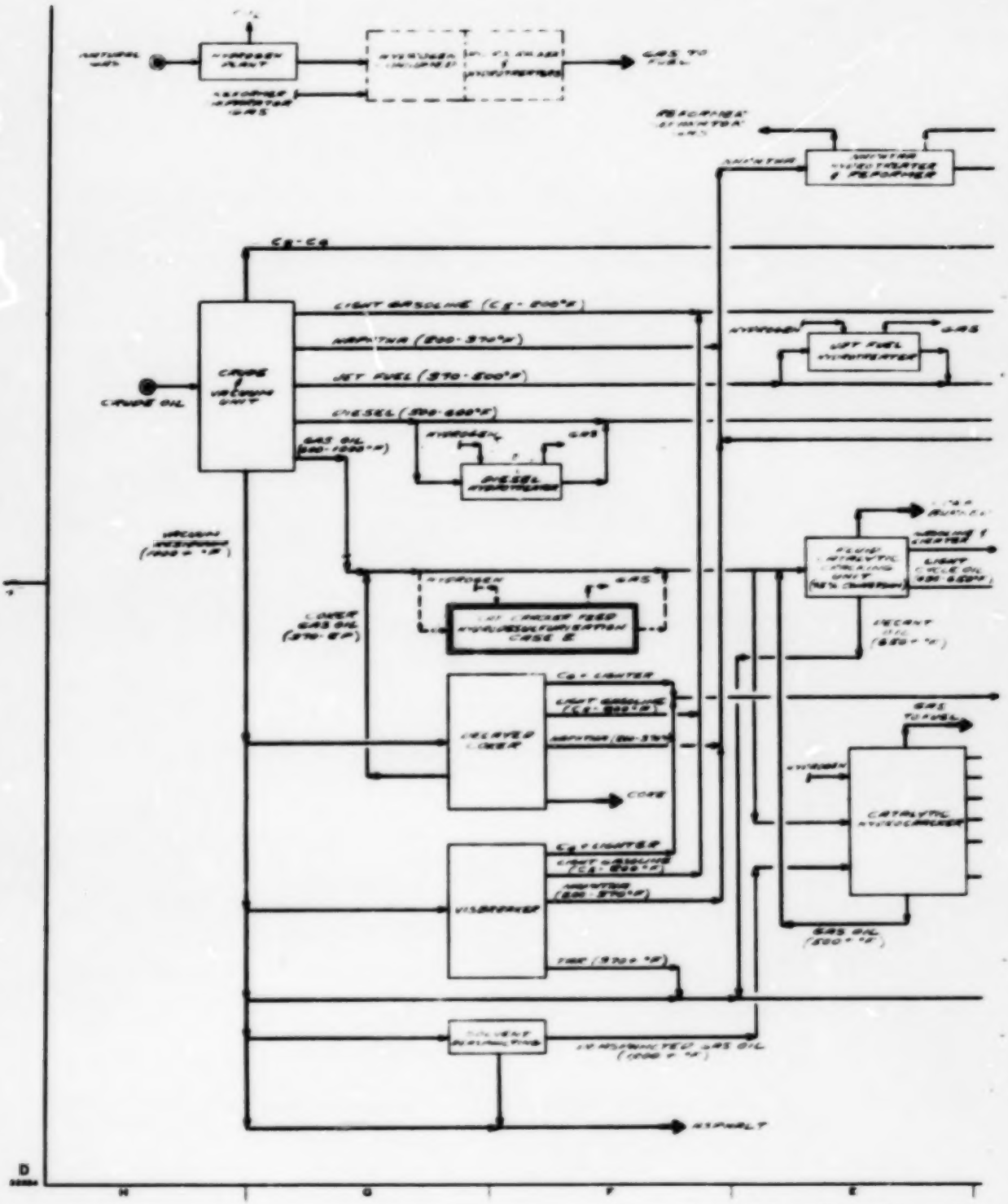

Figure 3-1. Flow schemes for

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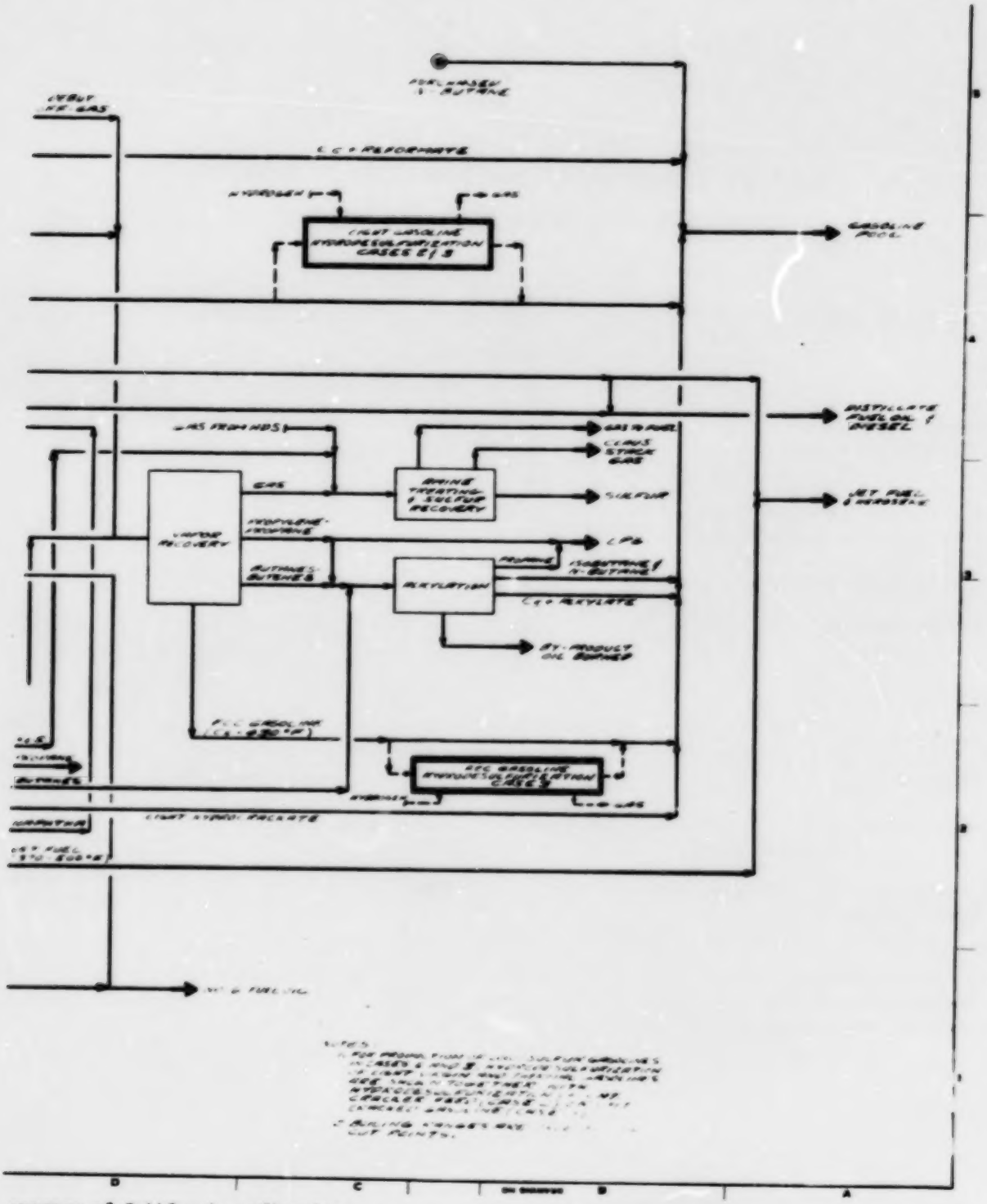

average of California refineries.

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Table 3-4. CAPACITIES OF PROCESS UNITS IN CASE 1 COMPARED WITH CALIFORNIA REFINERIES

PROCESS UNITS	VOL% OF CRUDE CAPACITY	
	Average of California Refineries in 1973	Case 1
Crude Distillation	100.0	100.0
Vacuum Distillation	52.1	51.5
Catalytic Cracking	26.5	24.4
Catalytic Hydrocracking	17.5	17.1
Thermal Cracking Gas Oil	1.8	-
Catalytic Reforming	26.0	24.0
Hydrotreating:		
Naphtha	23.8	15.8
Mid-Distillate	11.4	11.4
Other	3.6	-
Delayed Coking	14.1	12.3
Fluid Coking	4.0	-
Visbreaking	5.4	3.7
Alkylation, HF	0.9	5.0
Sulfuric Acid	4.1	
Aromatics, BTX Production	0.3	-
Isomerization, C_4	0.5	-
C_5 & C_6	0.7	-
Lube Production	1.3	-
Asphalt Production	5.4	2.2
Solvent Deasphalting	2.5	1.7

*At 670° F TBP cut point in crude oil

Table 3-5. COMPARISON OF PRODUCTS AND YIELDS

Basis: Yields are Vol% on crude input and for West Coast (PAD District 5) for January 1972-September, 1973. Properties of products are from 1973 sales in California.

	West Coast Production	Case 1	Case 2	Case 3
TOTAL GASOLINES				
Yield, Vol % on Crude Input	51.0	55.5	55.5	55.5
°API	58.5	61.5	62.6	61.6
Sulfur, wt%	0.046	0.053	0.006	0.006
Lead Anti-knock, Grams Per Gal.	2.1	2.1	2.1	2.1
Research Octane	97.2	97.1	97.4	96.0
Motor Octane	89.0	89.6	90.4	90.8
Reid Vapor Pressure	10.0	10.0	10.0	10.0
JET FUEL AND KEROSINE				
Yield, Vol% on Crude Input	11.0	11.6	11.6	11.6
°API	42.9	39.0	39.0	39.0
Sulfur, wt%	0.045	0.049	0.049	0.049
Aniline Point, °F	143	139	139	139
DIESEL AND NO. 2 FURNACE OIL				
Yield, Vol% on Crude Input	13.7	14.8	14.8	14.8
°API	35.0	35.7	35.6	35.7
Sulfur, wt%	0.27	0.26	0.26	0.26
Cetane Index	50.0	48.8	48.8	48.8
NO. 6 FUEL OIL				
Yield, Vol% on Crude Input	17.4	14.6	14.6	14.6
°API	11.0	10.8	11.3	10.8
Sulfur, wt%	1.5	2.4	1.7	2.4
Carbon Residue, wt%	11.2	9.1	9.1	9.1
OTHER PRODUCTS				
Yield, Vol% on Crude Input:				
Coke (5 bbl = 1 Short Ton)	4.5	3.1	3.1	3.1
Asphalt and Road Oil	3.3	2.2	2.2	2.2
Still Gas to Fuel	4.7	3.8	3.7	3.8
Liquefied Refinery Gas	2.5	2.9	3.3	2.9
Lube Oil, Wax, & Miscellaneous	1.2	None	None	None
APPARENT PROCESSING GAIN				
Vol% on Crude Input	6.4	6.4	7.0	6.4
LPG INPUT				
Vol% on Crude Input	1.0	1.2	0.8	1.2

Table 3-6. OVERALL REFINERY MATERIAL BALANCE - CASE 1

INPUT	BPCD	#/H	SULFUR CONTENT, #/H
Crude Oil	100,00	1,292,720	16,377
Purchased N-Butane	1,204	10,250	-
H_2 Plant: Nat. Gas-FOE	848	10,020	-
Water		22,550	-
Total Input	102,052	1,335,540	
OUTPUT			
Gas to Fuel - FOE	3,769	46,210	182
H_2S to Sulfur Recovery	-	7,030	6,613
LPG	2,874	21,360	-
Gasolines	55,519	592,760	315
Alkylation By-product Oil	6	80	-
Jet Fuel & Kerosine	11,582	140,060	68
Diesel & Distillate Fuel Oil	14,787	182,400	472
No. 6 Fuel Oil	14,629	212,010	5,167
Asphalt	2,200	33,540	1,017
Delayed Coke (5 bbl = 1 Short Ton)	3,100	51,660	1,723
Catalytic Cracker Coke Burned	-	20,450	820
CO_2 From H_2 Plant	-	27,560	-
NH_3 From Hydrocracker	-	420	-
Total	108,466	1,335,540	16,377
Apparent Gain	6,414		

Table 3-7. GASOLINE POOL - CASE I

	ISOBUTANE	N-BUTANE	LIGHT VIRGIN GASOLINE	LIGHT COKER GASOLINE	LIGHT VISBREAKER GASOLINE	REFORMATE	ALKYLATE	CAT. CRACKED GASOLINE	LIGHT HYDRO-CRACKATE	HDS. GASOLINE	TOTAL
TBP BOILING RANGE, °F			C5-300	C5-200	C5-200	C5-EP	C5-EP	C5-430	C5-300	C5-400	
VOL. FRACTION	0.003	0.075	0.108	0.017	0.002	0.399	0.090	0.263	0.081	0.082	1.000
BPCD	158	4,137	5,990	927	115	19,970	5,000	14,605	4,481	126	55,519
°API (SP. GR.)	(0.5626)	(0.584)	74.0	69.7	75.0	48.0	71.6	57.2	76.5	61.0	61.5
LB/H	1,290	35,210	60,060	9,490	1,150	229,340	50,740	159,620	44,410	1,450	592,760
REID VAPOR PRESSURE	82.5	59.1	9.0	6.7	6.5	3.5	3.1	6.7	12.0	7.0	10.0
OCTANE:											
RESEARCH CLEAR	102.6	93.8	70.0	81.1	81	94.0	94.1	93.2	82.8	63	90.1
RESEARCH + 3 cc	104.2	101.6	88.2	88.3	88	100.0	105.1	98.2	96.8	84	98.4
MOTOR CLEAR	97.6	90.3	68.2	67.7	68	84.8	93.0	82.2	82.5	63	83.0
MOTOR + 3 cc	103.0	100.4	86.6	75.5	76	90.7	107.0	87.2	99.6	85	92.0
OLEFINS, VOL %	--	--	--	37	37	1.0	--	17	--	--	5.5
AROMATICS, VOL %	--	--	3	4	4	34	--	34	2	--	21.8
SULFUR, WT %	--	--	0.019	0.49	0.04	--	--	0.158	--	--	0.053
LB/H	--	--	11	47	5	--	--	252	--	--	315

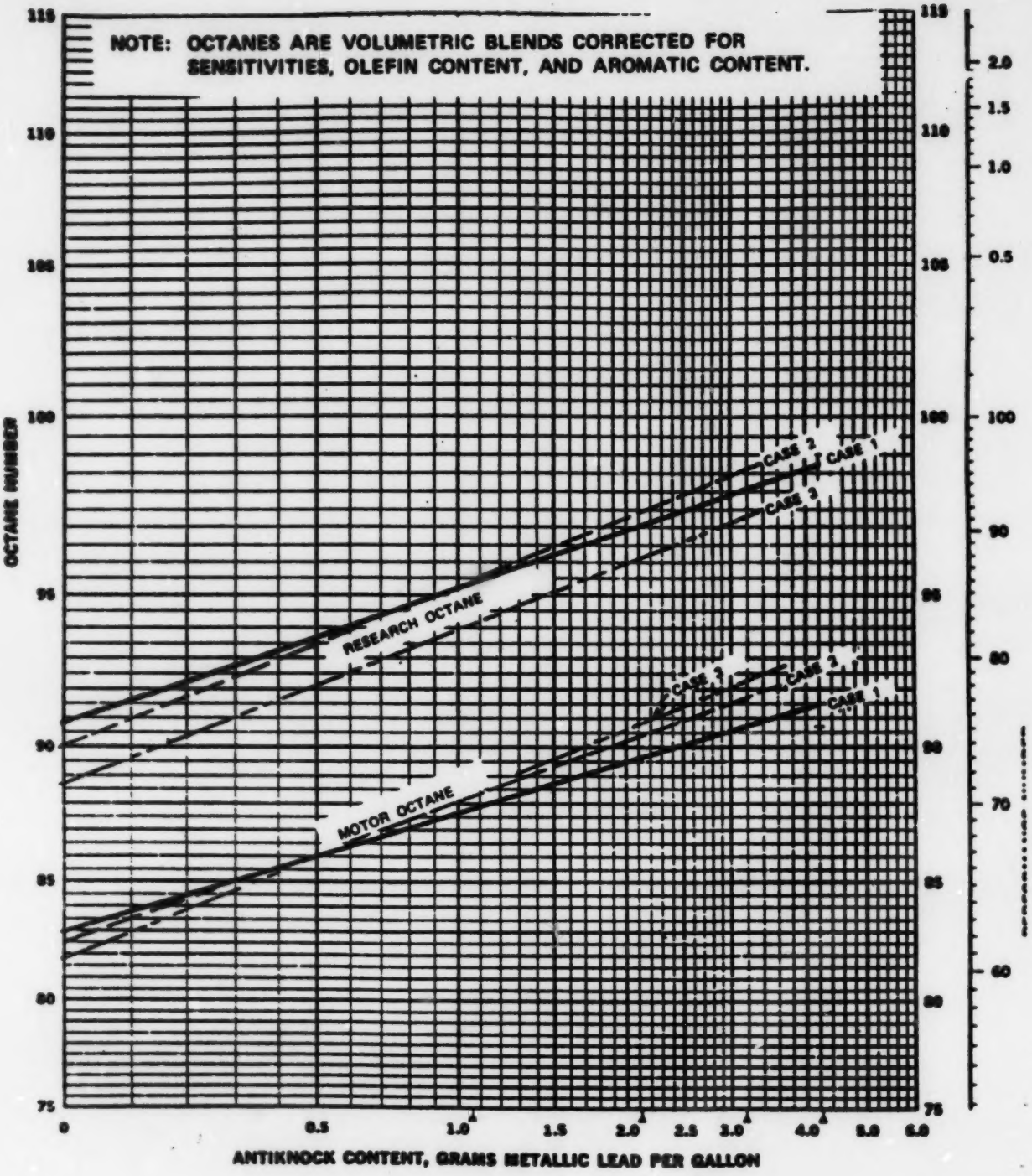
NOTE: OCTANES ARE VOLUMETRIC BLENDS CORRECTED FOR SENSITIVITIES, OLEFIN CONTENT, AND AROMATIC CONTENT.
OCTANE NUMBER
RESEARCH OCTANE
MOTOR OCTANE
CASE 1
CASE 2
CASE 3
ANTIKNOCK CONTENT, GRAMS METALLIC LEAD PER GALLON

Figure 3-2. Octanes of Total Gasoline Pool

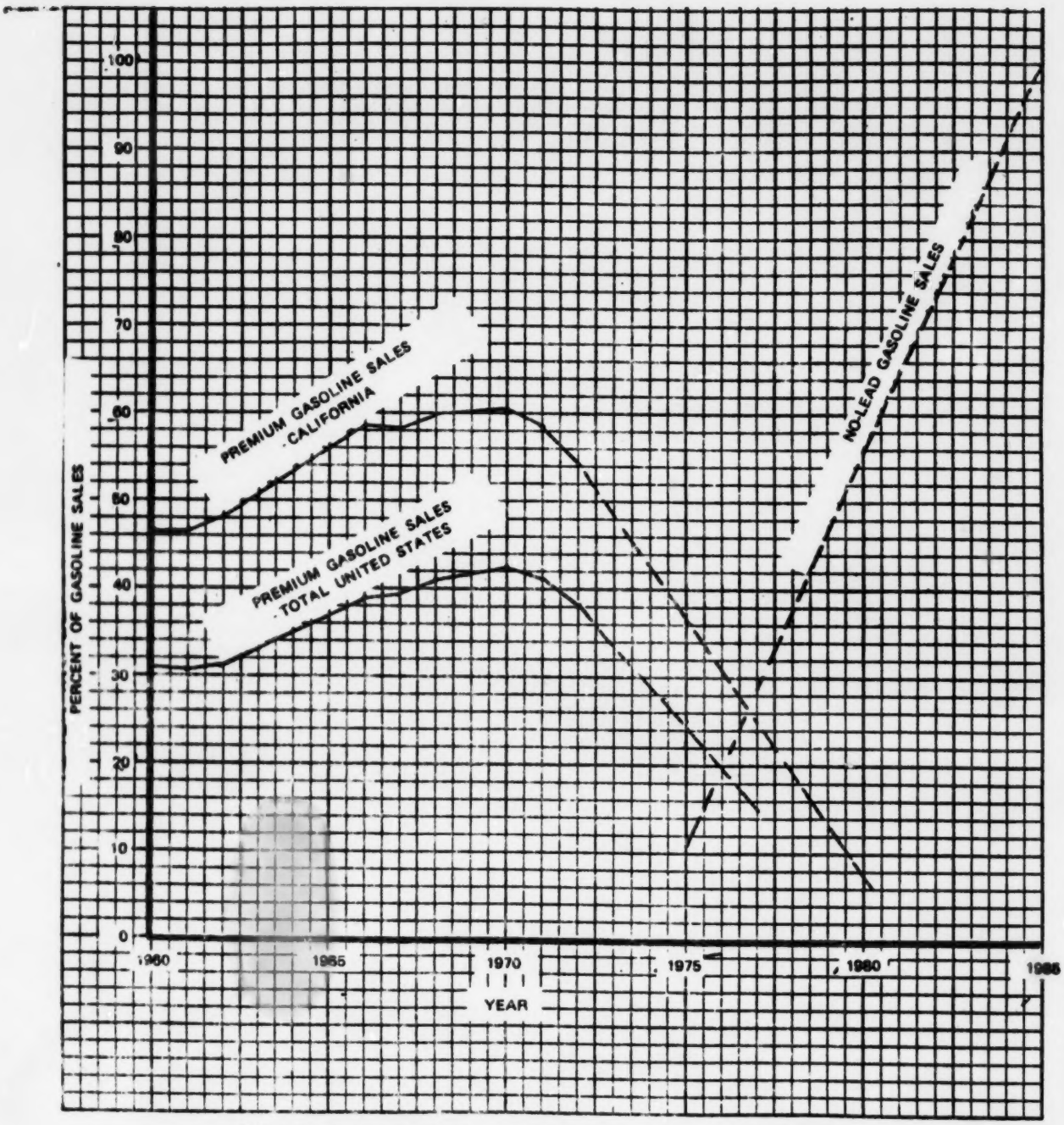

Figure 3-3. Projected Percent of Sales of Premium and No-Lead Gasoline in California

compression cars are junked. The projected sales percent of no-lead gasoline is assumed to follow the projected sales of new cars which require no-lead gasolines.

PRODUCTION OF NO-LEAD, LOW-SULFUR GASOLINE IN PRESENT CALIFORNIA REFINERIES

The time to plan, finance, and construct refining facilities to upgrade gasoline blending components requires about three years from the date of a firm decision to proceed. During the period until the additional gasoline-upgrade facilities are onstream, the no-lead, low-sulfur gasolines will have to be blended from low-sulfur components which can be produced in the present refining facilities.

In the California refineries, the present low-sulfur gasoline components are normal butane, reformate, light hydrocrackate and alkylate.

The potential production of no-lead, low-sulfur gasoline together with premium and regular gasoline were calculated attempting to meet the EPA regulations on lead phase-down using the blending components produced in Case 1. The results (Table 3-8) indicate that the projected percent of gasoline sales can be met in 1975 and and 1976. In 1977 and later years, the EPA limit on lead content would be exceeded.

No-lead gasoline and premium gasoline utilize the same gasoline blending components such as reformate and light hydrocrackate or alkylate. Regular gasoline will contain the lower-octane blending components which cannot be utilized in no-lead or premium gasoline blends. Therefore if the projected sales demand for no-lead or premium gasoline significantly increased from the projected sales, shortages of premium and no-lead gasoline may occur.

In 1977 and later years, octane up-grading will become necessary to meet the EPA regulations on lead phase-down. In 1977, it may be possible to increase the reformer severity. In the later years, new octane up-grading facilities will need to be installed. The processes for octane up-grading include isomerization of normal pentane and hexanes and reforming of heavy catalytic cracked naphtha.

In producing no-lead, low-sulfur gasoline, Table 3-8 shows that the sulfur contents by 1979 in the premium and regular gasolines will be about twice the present sulfur levels. In 1979, regular gasoline and premium gasoline would respectively contain 0.11 and 0.07 wt% sulfur.

Table 3-8. POTENTIAL GASOLINE PRODUCTION IN CASE 1[1] WITH LEAD PHASE-DOWN

Year	1972	1975	1976	1977	1978	1979
Lead Content, Grams/Gal						
Allowed by EPA	4.2[2]	1.7	1.4	1.0	0.8	0.5
Total Gasoline Pool	2.12	1.56	1.07	1.01	1.03	0.93
Premium Gasoline	2.65	2.91	2.00	2.07	2.75	3.00
Regular Gasoline	1.32	0.92	0.92	1.07	1.17	1.36
Potential Gasoline, Vol%						
No-Lead, Low-Sulfur (92 RON)	-	11	20	29	38	47
Premium (99.5 RON)	54	37	31	25	19	13
Regular (93.5 RON)	46	52	49	46	43	40
No-Lead Gasoline, Vol%						
N-Butane	-	9	9	9	9	9
Light Hydrocrackate	-	18	18	18	18	17
Reformate	-	73	73	73	73	70
Alkylate	-	-	-	-	-	4
Premium Gasoline, Vol%						
N-Butane	9	8	9	9	9	9
Alkylate	17	20	29	22	22	21
Reformate	40	33	26	31	31	24
FCC Gasoline	25	23	21	26	31	46
Light Hydrocrackate	9	16	15	12	7	-
Regular Gasoline, Vol%						
N-Butane	6	7	6	6	5	5
Isobutane	0.5	0.5	0.5	0.5	0.5	0.5
Light Coker & VB Gasoline	4	4	4	4	5	5
Reformate	31	30	27	15	5	-
FCC Gasoline	28	34	40	43	48	51
Light Hydrocrackate	7	-	-	-	-	-
Light Virgin Gasoline	23	21	22	23	25	27
HDS Gasoline	0.5	0.5	0.5	0.5	0.5	0.5
Alkylate	-	3	-	8	11	11

Table 3-8 (continued). POTENTIAL GASOLINE PRODUCTION IN CASE 1 (1) WITH LEAD PHASE-DOWN

Year	1972	1975	1976	1977	1978	1979
Gasoline Octanes						
No-Lead, Research	-	92.4	92.4	92.4	92.4	92.5
Motor	-	85.0	85.0	85.0	85.0	85.2
Premium, Research	99.6	99.5	99.5	99.5	99.5	99.5
Motor	92.4	93.5	96.8	95.2	92.6	91.7
Regular, Research	93.9	93.5	93.5	93.5	93.5	93.5
Motor	86.3	85.5	84.9	85.7	85.8	85.9
Sulfur, Wt%						
No-Lead, Low-Sulfur	-	-	-	-	-	-
Premium	0.033	0.037	0.034	0.043	0.050	0.074
Regular	0.058	0.076	0.087	0.094	0.104	0.112
Comment - See Note				(3)	(3)	(3)

NOTES:

(1) Gasoline blends are calculated at 10 pounds Reid vapor pressure using the gasoline components with the yields and properties from Case 1 for the "Average" of California refineries.

(2) Legal limit was 4.2 grams lead content per gallon prior to EPA regulations.

(3) In 1977, 1978 and 1979, the lead content in the total gasolines would exceed the EPA limits on lead content. Additional octane upgrading refining facilities will be required to meet the EPA limits on lead content.

CHAPTER 4

DESULFURIZATION OF GASOLINES

GENERAL

In order to calculate the costs of producing low-sulfur gasolines, the "Average of California Refineries" was taken as the basic refinery and then low-sulfur gasoline produced by two types of process additions:

- Hydrodesulfurization of catalytic cracker feedstock and hydrodesulfurization of the light virgin, light coker, and light visbreaker gasolines (Case 2).
- Hydrodesulfurization of catalytic cracker gasoline and hydrodesulfurization of the light gasolines (Case 3).

In this study, the costs were purposely made on the conservative (i.e. higher capital) side as follows:

- Investments included new units to provide the incremental capacities for hydrogen, amine treating and sulfur recovery. In Case 3, these units are small and may not be required.
- In Case 2, the catalytic cracker conversion was kept at 75% as in Case 1. Depending upon the whether the refinery catalytic cracker severity is coke limited or gas limited, it may be practical in Case 2 to increase the catalytic cracker conversion to make this case more attractive.

In Case 3, the octane of the catalytic cracked gasoline would be lower after hydrotreating due to partial olefin saturation. Economics debited the lower octane by penalizing the production of premium gasoline using the price differential between premium and regular gasolines. If additional octane up-grading were necessary the costs would further penalize Case 3.

CASE 2: AVERAGE CALIFORNIA REFINERY WITH HYDRODESULFURIZATION OF CATALYTIC CRACKER FEED AND LIGHT GASOLINES

In Case 2, the crude oil and refinery process units would be the same as Case 1 of the "Average of California Refineries" with the following additions:

- Hydrodesulfurization of catalytic cracker feedstock.
- Light gasoline hydrodesulfurization.
- New units for incremental needs for hydrogen, amine treating, and sulfur recovery.

The flow scheme for "Average of California Refineries" shows the added hydrodesulfurization unit. The yields and product properties are listed in Table 3-5 together with the information for the West Coast production and Case 1. For Case 2, the overall material balance

is shown in Table 3-9 and the gasoline pool is shown in Table 3-10 The sulfur content of the total gasolines would be 0.006 weight percent.

The incremental investment to product low-sulfur gasolines is estimated to be 18.7 million dollars (Table 3-11) in Case 2 for a 100,000 bpcd refinery.

In California, there are eleven refineries which are larger than 75,000 bpsd. The crude capacities of these eleven refineries total 1,402,000 bpsd which is 78% of the total crude capacity of all refineries in California. If new facilities were installed to produce low-sulfur gasolines in these eleven refineries by desulfurizing light virgin gasoline, light thermal gasolines, and catalytic cracker feedstock (Case 2), an investment of about 250 million would be required based on May, 1974 costs.

Economics show that this desulfurization scheme would add 1.1 cents per gallon to the costs of producing gasoline (Table 3-16).

The potential production of no-lead, premium and regular gasolines were calculated attempting to meet the EPA regulations on lead phase-down using the blending components produced in Case 2. All the gasolines would be low-sulfur. The results (Table 3-12) indicate that the projected percent of gasoline sales can be met in 1976. In 1977 and later years, the EPA limit on lead content would be exceeded.

Results in Table 3-16 for Case 2 and in Table 3-8 for Case 1 indicate that refiners should start planning installation of new octane up-grading facilities or that EPA should relax the lead phase-down regulations to about the 1.4 grams per gallon for 1976 and later years.

CASE 3: AVERAGE CALIFORNIA REFINERY WITH HYDRODESULFURIZATION OF CATALYTIC CRACKED GASOLINE AND LIGHT GASOLINES

In Case 3, the crude oil and refinery process units would be the same as Case 1 of the "Average of California Refineries" with the following additions:

- Hydrodesulfurization of catalytic cracked gasoline.
- Light gasoline hydrodesulfurization.
- New units for incremental needs for hydrogen, amine treating, and sulfur recovery.

Table 3-9. OVERALL REFINERY MATERIAL BALANCE - CASE 2

INPUT	BPCD	#/H	SULFUR CONTENT, #/H
Crude Oil	100,000	1,292,720	16,377
Purchased N-Butane	796	6,770	
H_2 Plant: Nat. Gas-FOE	1,076	12,720	
Water		28,620	
Total	101,872	1,340,830	16,377
OUTPUT			
Gas to Fuel - FOE	3,746	46,120	183
H_2S to Sulfur Recovery		9,370	9,100
LPG	3,335	24,860	
Gasoline	55,536	589,860	36
Alkylation	5	70	
Jet Fuel & Kerosine	11,582	140,060	68
Diesel & Distillate Fuel Oil	14,821	182,860	473
No. 6 Fuel Oil	14,587	210,660	3,673
Asphalt	2,200	33,540	1,017
Delayed Coke (5 bbl=1 Short Ton)	3,100	51,660	1,723
Catalytic Cracker Coke Burned		16,070	104
CO_2 From H_2 Plant		34,980	
NH_3 From Hydrocracker		420	
Total	108,912	1,340,830	16,377
Apparent Gain	7,040		

Table 3-10. GASOLINE POOL - CASE 2

	ISOBUTANE	N BUTANE	HDS LIGHT GASOLINE	REFORMATE	ALKYLATE	CAT CRACKED GASOLINE	LIGHT HYDRO CRACKATE	HDS GASOLINES	TOTAL
TBP BOILING RANGE °F			C5-200	C5+EP	C5 EP	C5-430	C5-200	C5 EP	
VOL FRACTION	0.006	0.068	0.127	0.359	0.090	0.264	0.081	0.005	1.000
BPCD	316	3,793	7,040	19,970	5,000	14,678	4,481	256	55,536
°API (SP. GR.)	(0.56,26)	(0.584)	73.6	98.0	97.4	58.6	76.5	61.2	82.6
LB/H	2,580	32,280	70,750	229,340	50,860	156,940	44,410	2,760	589,860
REID VAPOR PRESSURE	82.5	59.1	8.7	3.5	3.2	7.1	12.0	7.0	10.0
OCTANE									
RESEARCH CLEAR	102.6	93.8	68.7	94.0	94.3	91.9	82.8	63	89.3
RESEARCH + 3 cc	104.2	101.6	88.3	100.0	103.4	99.2	96.8	84	98.6
MOTOR CLEAR	97.6	90.3	67.1	84.8	95.3	81.0	82.5	63	82.5
MOTOR + 3 cc	103.0	100.4	87.0	90.7	107.3	88.3	99.6	85	92.5
OLEFINS, VOL %				1.0		15.6	—		4.9
AROMATICS, VOL %			3.1	54		32	2		21.3
SULFUR, WT %			0.004	—		0.02	—		0.009
LB/H			3			31	—		36

Table 3-11. INVESTMENT FOR DESULFURIZATION FACILITIES - CASE 2

FACILITY	CAPACITY	INVESTMENT, MILLION DOLLARS
Refinery Size	100,000 BPCD	-
Light Gasoline Hydrodesulfurizer	7,400 BPSD	3.2
Catalytic Cracker Feed Hydrodesulfurizer	25,700 BPSD	6.2
Amine H_2S Removal	Amine Circulation 193 GPM	1.0
Sulfur Recovery (Claus Plant)	30 Short Tons/Day	0.5
Hydrogen Plant	8.3 MM SCF/D	3.5
Onsite		14.4
Offsite (at 30% of Onsite)		4.3
Total Investment		18.7

* Investment includes paid-up royalties (if applicable) plus initial charges of catalysts. Investment at May, 1974 levels.

Table 3-12. POTENTIAL GASOLINE PRODUCTION IN CASE 2 WITH LEAD PHASE-DOWN[1]

Year	1976	1977	1978	1979
Lead Content, Grams/Gal				
Allowed By EPA	1.4	1.0	0.8	0.5
Total Gasoline Pool	1.24	1.03	0.93	0.76
Premium Gasoline	2.41	2.28	2.38	1.87
Regular Gasoline	1.00	1.00	1.11	1.28
Potential Gasoline, Vol%				
No-Lead, Low-Sulfur (92 RON)	20	29	38	47
Premium (99.5 RON)	31	25	19	13
Regular (93.5 RON)	49	46	43	40
No-Lead Gasoline, Vol%				
N-Butane	8	9	9	9
Light Hydrocrackate	13	18	18	17
Reformate	38	73	73	72
FCC Gasoline	28	-	-	2
Alkylate	13	-	-	-
Premium Gasoline, Vol%				
N-Butane	8	7	9	9
Alkylate	12	22	22	35
Reformate	41	15	29	16
FCC Gasoline	30	44	33	40
Light Hydrocrackate	9	12	7	-
Regular Gasoline, Vol%				
N-Butane	5	5	4	3
Isobutane	1	1	1	1
HDS Light Gasoline	26	28	30	32
Reformate	32	24	6	-
Alkylate	5	8	11	10
Catalytic Cracked Gasoline	24	33	47	53
Light Hydrocrackate	6	-	-	-
HDS Gasoline	1	1	1	1

Table 3-12 (continued). POTENTIAL GASOLINE PRODUCTION IN CASE 2 WITH LEAD PHASE-DOWN(1)

Year	1976	1977	1978	1979
Gasoline Octanes				
No-Lead, Research	92.3	92.4	92.4	92.5
Motor	84.6	85.1	85.1	85.1
Premium, Research	99.5	99.5	99.5	99.5
Motor	91.5	92.2	92.5	92.9
Regular, Research	93.5	93.5	93.5	93.5
Motor	86.7	86.3	86.5	85.8
Sulfur, Wt%				
No-Lead, Low-Sulfur	0.006	0.000	0.000	0.000
Premium	0.006	0.010	0.007	0.009
Regular	0.006	0.008	0.011	0.013
Comments - See Note		(2)	(2)	(2)

NOTES:

(1) Gasoline blends are calculated at 10 pounds Reid vapor pressure using the gasoline components in Case 2.

(2) In 1977, 1978 and 1979, the lead content in the total gasolines would exceed the EPA limits on lead content. Additional octane upgrading refining facilities will be required to meet the EPA limits on lead content.

Table 3-13. OVERALL REFINERY MATERIAL BALANCE - CASE 3

INPUT	BPCD	#/H	SULFUR CONTENT, #/H
Crude Oil	100,000	1,292,720	16,377
Purchased N-Butane	1,176	10,010	-
H_2 Plant: Nat. Gas- FOE	929	10,980	-
Water	-	24,710	-
Total	102,105	1,338,420	16,377
OUTPUT			
Gas to Fuel-FOE	3,769	46,210	182
H_2S to Sulfur Recovery	-	7,320	6,892
LPG	2,874	21,360	-
Gasoline	55,533	592,710	36
Alkylation By-Product Oil	6	80	-
Jet Fuel & Kerosine	11,582	140,060	68
Diesel & Distillate Fuel Oil	14,787	182,400	472
No. 6 Fuel Oil	14,629	212,010	5,167
Asphalt	2,200	33,540	1,017
Delayed Coke (5 bbl= 1 Short Ton)	3,100	51,660	1,723
Catalytic Cracker Coke Burned	-	20,450	820
CO_2 From H_2 Plant	-	30,200	-
NH_3 From Hydrocracker	-	420	-
Total	108,480	1,338,420	16,377
Apparent Gain	6,375		

Table 3-14. GASOLINE POOL - CASE 3

	ISOBUTANE	N-BUTANE	HDS LIGHT GASOLINE	REFORMATE	ALKYLATE	HDS CAT CRACKED GASOLINE	LIGHT HYDRO-CRACKATE	HDS GASOLINE	TOTAL
TBP BOILING RANGE °F			C5-200	C5-EP	C5-EP	C5-430	C5-200	C5-400	
VOL. FRACTION	0.003	0.074	0.127	0.359	0.090	0.264	0.081	0.002	1.000
BPCD	158	4,109	7,040	19,970	5,000	14,639	4,481	136	55,533
API (SP. GR.)	(0.5626)	(0.584)	73.6	48.0	71.6	57.4	76.5	61.0	61.6
LB/H	1,290	34,970	70,750	229,340	50,746	159,760	44,410	1,450	592,710
REID VAPOR PRESSURE	52.5	59.1	8.7	3.5	3.1	6.7	12.0	7.0	10.0
OCTANE									
RESEARCH CLEAR	102.6	93.8	68.7	94.0	94.1	87.6	82.8	63	88.14
RESEARCH + 3 cc	104.2	101.6	86.3	100.0	105.1	94.0	96.8	84	97.23
MOTOR CLEAR	97.6	90.3	67.1	84.8	93.0	78.3	82.5	63	81.79
MOTOR + 3 cc	103.0	100.4	87.0	90.7	107.0	89.3	99.6	85	92.79
OLEFINS, VOL %				1.0		7.7	--		2.4
AROMATICS, VOL %			3.1	58		38	2		21.7
SULFUR, WT %			0.004			0.021	--		0.006
LB/H			3			33			36

The yields and product properties for Case 3 are listed in Table 3-5 together with the information for the West Coast production and Cases 1 and 2.

In removing sulfur from catalytic cracked gasoline, 87% desulfurization was selected since this yields about the same sulfur content in the total gasolines as in Case 2 (0.006 wt% sulfur). At this desulfurization severity, 55% of the olefins in the catalytic cracked gasolines would be hydrogenated and lower the octane. In the economics, the lower octane shows a penalty of 0.1 cent per gallon of gasoline for 0.3 octane (Research/2+Motor/2) difference at 1.0 gram lead per gallon.

In Case 3, the incremental investment to produce low-sulfur gasolines is estimated to be 13.5 million dollars (Table 3-15) for a 100,000 bpcd refinery. Economics show that this desulfurization scheme would add 1.0 cents per gallon to the costs of producing gasoline (Table 3-16).

SULFUR DISTRIBUTION IN REFINERY PRODUCTS AND EMISSIONS

Sulfur contained in the crude oil to the refinery is distributed in the products, recovered as elemental sulfur, and emitted as SO_2 to the atmosphere as shown in Table 3-17.

In Case 1, the sulfur in the crude oil is distributed 37.8% to residual fuel oil and asphalt, 38.0% recovered as elemental sulfur and 8.5% emitted as SO_2 to the atomosphere. By desulfurizing the catalytic cracker feedstock in Case 2, the recovery of elemental sulfur can be increased to 52.3% and the emission decreased to 5.1%.

DISCUSSION

This study was based on a refinery model which represents an average of the refineries in California. However, each refinery in California may be distinctly different from this refinery model in both the process units, crude mix charged, operating conditions and products. Each refinery bases its operations on market demands, availability of crudes, limitations of process units, and flexibility of operating conditions. If it becomes mandatory to produce only low-sulfur gasolines, each California refinery should prepare their own economics as to which process scheme best suits its refinery or refineries.

It is believed that desulfurization of the catalytic cracker feed will generally be the most attractive.

Table 3-15. INVESTMENT FOR DESULFURIZATION - CASE 3

FACILITY	CAPACITY	INVESTMENT,* MILLION DOLLARS
Refinery Size	100,000 BPCD	-
Light Gasoline Hydrodesulfurizer	7,400 BPSD	3.2
FCC Gasoline Hydrodesulfurizer	15,400 BPSD	4.4
Amine H_2S Removal	Amine Circulation 19 GPM	0.3
Sulfur Recovery (Claus Plant)	3.5 Short Tons/Day	0.1
Hydrogen Plant	4.0 MM SCF/D	2.4
Onsite		10.4
Offsite (at 30% of Onsite)		3.1
Total Investment		13.5

* Investment includes paid-up royalties (if applicable) plus initial charges of catalysts.

Table 3-16. COSTS FOR GASOLINE DESULFURIZATION*

Case	2	3
Refinery Capacity, BPCD	100,000	100,000
Investment for Gasoline Desulfurization, Million Dollars	18.7	13.5
Years to Payout	5	5
Return, Percent Per Year	20	20
Million Dollars Per Year:		
Cash Flow	3.74	2.70
Depreciation	1.05	0.90
Income After Tax	2.69	1.80
Income Tax at 48%	2.48	1.66
Tax Base	5.17	3.46
Operating Costs:		
Depreciation	1.05	0.90
Operating Manpower	0.33	0.33
Utilities	3.10	1.45
Catalyst Replacement	0.14	0.04
Interest	0.94	0.68
Maintenance	0.66	0.48
Local Taxes & Insurance	0.28	0.20
Incremental Product Credits	-2.28	0.15
Debit for Lower Gasoline Octane	-	0.85
Total Operating Costs	4.22	5.08
Total added Costs for Gasoline Desulfurization: Million Dollars Per Year (Tax Base + Oper. Costs)	9.39	8.54
Cents Per Gallon Gasoline	1.10	1.00

* Incremental costs above Case 1.

Table 3-17. SULFUR DISTRIBUTION IN REFINERY PRODUCTS AND EMISSIONS

	SULFUR DISTRIBUTION, % *		
	Case 1	Case 2	Case 3
Gasoline	1.9	0.2	0.2
Jet Fuel & Kerosine	0.4	0.4	0.4
Diesel & Distillate Fuel Oil	2.9	2.9	2.9
No. 6 Fuel Oil	31.6	22.4	31.6
Asphalt	6.2	6.2	6.2
Delayed Coke	10.5	10.5	10.5
Recovered as Elemental Sulfur	38.0	52.3	39.6
Emitted as SO_2 to Atmosphere	8.5	5.1	8.6
Total	100.0	100.0	100.0

* As percent of sulfur in crude oil.

Table 3-18. REFINERY RUNS - PAD DISTRICT 5 (WEST COAST)

Basis: Bu Mines Statistics for January, 1972 through September, 1973.

INPUT	MILLION BARRELS	VOL% ON CRUDE INPUT
Crude Oil - Total	1,222	100.0
U. S.	757	61.9
Foreign	465	38.1
Natural Gas Liquids - Total	35	2.9
LPG	12	1.0
Nat. Gas.	23	1.9
Total Input	1,257	102.9
OUTPUT		
Gasoline (1)	623	51.0
Liquefied Refinery Gas (2)	30	2.5
Jet Fuel and Kerosine (3)	134	11.0
Diesel and Distillate Fuel Oil	167	13.7
Residual Fuel Oil	213	17.4
Lube Oil and Wax	11	0.9
Coke (5 bbls = 1 short ton)	55	4.5
Asphalt and Road Oil	40	3.3
Still Gas to Fuel	58	4.7
Miscellaneous	4	0.3
Total Output	1,335	109.3
Processing Gain	78	6.4

NOTES:

(1) Includes motor gasolines, aviation gasolines, petrochemical feedstocks (aromatics) and special naphthas.

(2) Includes ethylene-ethane and liquefied refinery gas for fuel and chemical uses.

(3) Includes jet fuel (kerosine type) and 50% of naphtha-type jet fuel.

Table 3-19. AVERAGE PROPERTIES OF PRODUCT SALES IN SOUTHERN CALIFORNIA

	REGULAR GASOLINE	PREMIUM GASOLINE	REGULAR GASOLINE	PREMIUM GASOLINE	AVERAGE TOTAL GASOLINE	KEROSINE	JET A FUEL	DIESEL FUEL (TRUCKS, TRACTORS)	NO. 2 FURNACE OIL	NO. 6 FUEL OIL
BUREAU MINES SURVEY	WINTER 1972-1973	WINTER 1972-1973	SUMMER 1973	SUMMER 1973		1973	1973	1973	1973	1973
GRAVITY, °API	59.2	58.4	58.5	58.2	58.5	41.7	42.9	35.3	34.5	11.0
ASTM DISTILLATION, °F										
IBP	87	86	93	92		339	331	395	388	
10%	113	115	124	126		370	369	453	446	
30%	159	167	166	173						
50%	209	219	212	219		412	415	520	519	
70%	269	264	270	263						
90%	346	324	342	327		469	473	600	602	
EP	412	403	412	409		516	512	643	647	
SULFUR, WT %	0.069	0.042	0.046	0.034	0.046	0.073	0.045	0.32	0.22	1.50
ANILINE POINT, °F						138	143	149	146	
CETANE NUMBER (INDEX)								47.3 (50.7)	(49.0)	
SMOKE POINT, MIN							23.3			
VISCOSITY, CS AT 100°F								2.95	3.20	
VISCOSITY, FUROL AT 122°F										159
CARBON RESIDUE, WT %										11.2
LEAD, g/gal	1.24	2.64	1.40	2.65	2.12					
OCTANE NUMBER:										
RESEARCH	93.8	99.9	93.3	99.1	97.2					
MOTOR	85.2	91.6	85.2	91.2	89.0					
(RESEARCH + MOTOR)/2	89.5	95.8	89.3	95.2	93.1					
REID VAPOR PRESSURE	11.1	11.0	8.9	9.0	10.0					
SALES, %	37	63	42	58						

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APPENDIX A
SURVEY OF REFINERIES
IN CALIFORNIA

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CALIFORNIA

Company and location	Crude capacity b/cd	Crude capacity b/sd	Vacuum distillation	Charge capacity—b/sd: Thermal operations	Cat cracking—Fresh feed	Cat cracking—Recycle	Cat reforming	Cat hydrocracking	Cat hydrorefining	Cat hydrotreating	Production capacity—b/sd: Alkylation	Aromatics-isomerization	Lubes	Asphalt	Coke t/d
Atlantic Richfield Co.—Carson	165,000	173,000	93,000	[1]23,000 [2]37,000 [3]25,500	[1]57,000	8,000	[1]32,000	[1]17,000	[1]18,000	[1]32,000 [2]18,000	[1]7,200	[1]2,400 [2]13,000			1,650
Beacon Oil Co.—Hanford	12,000	12,100		[1]500 [2]2,750			[1]1,650								
Champlin Petroleum Co.—Wilmington	28,750	30,000	18,600	[1]9,650											
Carson Oil Co. (Leased from Golden Eagle Refining Co.)—Torrance	6,900	7,000													575
Douglas Oil Co. of California— Paramount	35,000	36,000	21,000				[1]6,400		[1]7,000	[1]6,400					
Santa Maria	8,200	8,500	7,500											14,000	
Edgington Oil Co.—Long Beach	15,000	16,000												5,800	
Edgington Oxnard Refinery—Oxnard	NR	2,500												5,000	
Exxon Co.—Benicia	86,000	95,000	47,000	[1]23,000	[1]46,000	9,300	[1]24,000	[1]24,000	[1]22,500	[1]21,000 [2]18,500 [3]4,000	[1]12,000				900
Fletcher Oil & Refining Co.—Carson	15,200	16,000					[1]4,000								
Golden Bear Division, Witco Chemical Corp.—Oildale	9,350	9,500	9,500					[1]1,000							
Gulf Oil Co.—Santa Fe Springs	49,800	52,000	21,900	[1]13,800	[1]13,500	300	[1]19,000	[1]11,000		[1]12,000	[1]3,000		4,000	3,200 4,000	
Kern County Refinery Inc.— Bakersfield	12,000	13,500	5,000	[1]6,000			[1]3,000			[1]3,500				1,200	
Lunday-Thagard Oil Co.—South Gate	5,000	5,200	3,000											1,600	
Macmillan Ring-Free Oil Co. Inc.— Signal Hill	10,000	10,000													
Mobil Oil Corp.—Torrance	123,500	130,000	95,000	[1]16,000 [2]46,640	[1]56,000	None	[1]17,500 [2]18,500	[1]8,000		[1]23,000 [2]15,000 [3]23,000	[1]10,500				2,800
Mohawk Petroleum Corp. Inc.— Bakersfield	17,000	17,500					[1]2,500			[1]2,500					
Newhall Refining Co. Inc.—Newhall	NR	6,500	3,000												
Phillips Petroleum Co.—Avon	110,000	NR	74,500	[1]42,000	[1]47,000	NR	[1]32,500	[1]22,000		[1]34,500	[1]10,500	[1]2,700	1,670		
Powerine Oil Co.—Santa Fe Springs	28,500	30,000	14,000		[1]10,000	1,000	[1]6,300	[1]2,200	[1]8,000	[2]7,000 [3]5,000*	[1]2,300			5,000	1,200
San Joaquin Refining Co.—Oildale	17,000	18,000	7,000												
Sequoia Refining Corp.—Hercules	27,000	28,300	5,900											3,360	
Shell Oil Co.—Martinez	100,000	103,000	56,600		[1]46,000	40,000	[1]15,800 [2]25,000	[1]2,900 [2]18,000	[1]50,000	[1]15,400 [2]16,000 [3]6,100 [4]15,000 [5]11,000 [6]11,000 [7]30,000 [8]33,000 11,000	[1]6,600		4,500	10,400	
Wilmington	86,000	88,000	60,000	[1]30,000	[1]35,000	5,000	[1]21,000				[1]8,600	[1]3,800			1,800
Standard Oil Co. of California— Bakersfield	NR	26,000		[1]9,000			[1]5,000			[1]5,000				1,100	
El Segundo	NR	220,000	103,000	[1]50,000	[1]40,000	15,000	[2]15,000 [3]7,000	[1]45,000		[2]40,000 [3]12,000 [4]18,0000	[1]5,400	[1]1,500		8,350	2,200
Richmond	NR	190,000	150,000		[1]40,000	15,000	[1]69,000	[1]68,000		[2]44,000 [3]3,200	[1]8,500	[1]1,500 [2]2,000	10,000	11,000	
Sunland Refining Corp.—Bakersfield	8,500	NR					[1]1,000								
Tenneco—Bakersfield	1,200	NR													
Texaco Inc.—Wilmington[4]	77,000	NR		[1]48,000	[1]28,000	NR	[1]35,000	[1]20,000		[1]23,000	[1]4,400	[1]1,200			1,650
Toscopetro Corp.—Bakersfield	26,500	27,000	17,000	[1]6,000	[1]10,000	2,000	[2]12,500	[2]12,000		[2]5,000	[1]1,800				180
Union Oil Co. of California[5]— Los Angeles	104,000	107,000	83,000	[1]20,000	[1]45,000	7,000	[1]29,000	[1]21,000		[1]37,000 [2]33,000	[1]8,000			10,000	
San Francisco	95,000	99,000	38,500	[1]42,500			[1]26,000	[1]30,000		[2]21,000 [3]8,000 [4]14,000			3,600	6,150	1,850
West Coast Oil Co.—Oildale	12,700	13,000	[1]2,000											2,000	
Total**	1,714,900	1,796,700	936,000	456,640	476,600	126,000	472,650	314,300	105,500	651,800	88,300	28,290	23,770	92,110	14,985

LEGEND

Processes in table are identified by numbers

Cat Hydrorefining
1. Residual desulfurizing
2. Heavy gas-oil desulfurizing
3. Residual visbreaking
4. Cat cracker and cycle stock feed pretreatment
5. Middle distillate
6. Other

Cat Hydrotreating
1. Pretreating cat-reformer feeds
2. Naphtha desulfurizing
3. Naphtha olefin or aromatics saturation
4. Straight-run distillate
5. Lube oil "polishing"
6. Other distillates
7. Other

Aromatics/Isomerization
1. BTX
2. Hydrodealkylation
3. Cyclohexane
4. C_4 feed
5. C_5 feed
6. C_8 and C_9 feed

Cat Reforming
Semiregenerative:
1. Conventional catalyst
2. Bimetallic catalyst

Cyclic:
3. Conventional catalyst
4. Bimetallic catalyst

Other:
5. Conventional
6. Bimetallic

Cat Hydrocracking
1. Distillate upgrading
2. Residual upgrading
3. Lube-oil manufacturing
4. Other

Thermal Process
1. Gas-oil cracking
2. Visbreaking
3. Fluid coking
4. Delayed coking
5. Other

Alkylation
1. Sulfuric acid
2. Hydrofluoric acid

Cat Cracking
1. Fluid
2. Thermofor
3. Houdriflow

NR—Not reported

*Diesel and jet. †Gasoline. ‡Turbine fuel. §Jet. ¶All figures are calendar day. Stream-day figures not reported. ‖Turbine aromatics saturation. **State totals include figures converted to stream-day or calendar-day basis. Cat cracking recycle total includes figures not reported (with recycle estimated at 30% of fresh feed).

APPENDIX B

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--------January 28, 1974

"Where District 5 Now Gets Crude, Products"

--------March 18, 1974

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